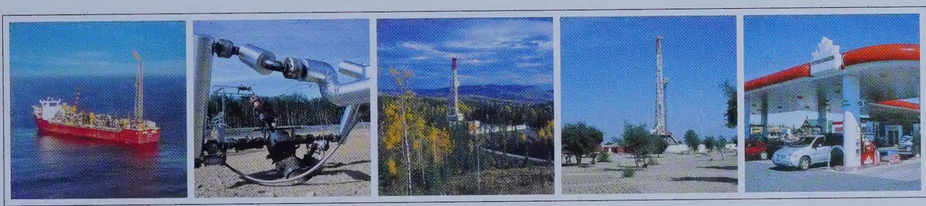
2002 ANNUAL REPORT

PROFITABILITY AND EXCEPTIONAL GROWTH



PETRO-CANADA

HIGHLIGHTS

(stated in millions of Canadian dollars, unless otherwise indicated)	**2002**	2001	2000
FINANCIAL			
Earnings from operations [1]	**1 024**	912	879
Net earnings	**974**	846	859
Cash flow	**2 276**	1 688	1 870
Per share *(dollars)*			
Earnings from operations [1]	**3.90**	3.44	3.23
Net earnings – basic	**3.71**	3.19	3.15
Net earnings – diluted	**3.67**	3.16	3.13
Cash flow	**8.66**	6.37	6.87
Dividends	**0.40**	0.40	0.40
Expenditures on property, plant and equipment and exploration	**1 861**	1 681	1 203
Return on capital employed *(per cent)*	**13.9**	14.8	16.0
Operating return on capital employed *(per cent)* [1]	**14.5**	15.8	16.4
Cash flow return on capital employed *(per cent)*	**30.5**	28.2	33.2
Debt	**3 057**	1 401	1 774
Debt to debt plus equity *(per cent)*	**34.6**	22.3	28.4
Debt to cash flow *(times)*	**1.3**	0.8	0.9

1 Earnings from operations are earnings before gains or losses on foreign currency translation and on disposal of assets. In 2000, earnings from operations are before reorganization costs.

OPERATING			
Total production *(thousands of barrels of oil equivalent per day)* [1]	**382.4**	196.5	212.2
Crude oil and field natural gas liquids production, before royalties *(thousands of barrels per day)*	**244.9**	77.4	89.2
Natural gas production, before royalties, excluding injectants *(millions of cubic feet per day)*	**825**	714	738
Proved oil and field natural gas liquids reserves, before royalties *(millions of barrels)*	**830**	450	414
Proved natural gas reserves, before royalties *(trillions of cubic feet)*	**2.8**	2.2	2.3
Refined petroleum product sales *(thousands of cubic metres per day)*	**55.7**	54.5	55.4
Refinery crude capacity utilization *(per cent)*	**101**	96	101

1 Natural gas production is converted using 6 000 cubic feet of gas for one barrel of oil.

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FRONT COVER PHOTOS:
(from left) Terra Nova FPSO; MacKay River production well; Foothills exploration; North Africa operations; Canada's Gas Station.

DELIVERING PROFITABILITY AND EXCEPTIONAL GROWTH

> Effective execution drove profitability gains

> International acquisition doubled production and created a new platform for future growth

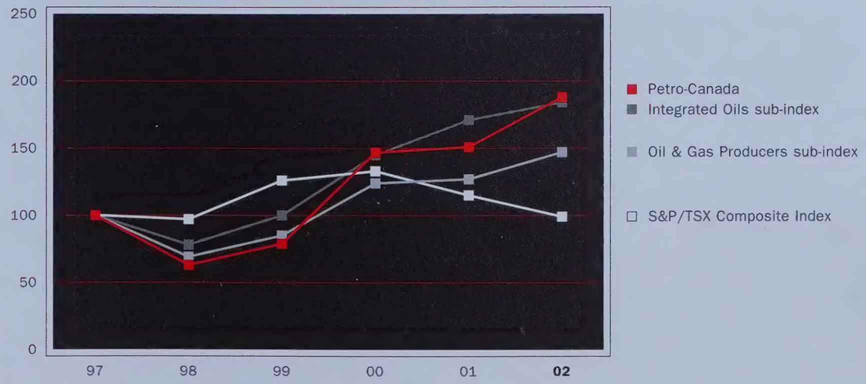
> Major offshore oil project on stream at Terra Nova

> Major *in situ* oil sands project on stream at MacKay River

> Marketing excellence recognized with Convenience Store Chain of the Year award

FIVE-YEAR SHARE PRICE PERFORMANCE

Petro-Canada shares rose 88 per cent from year-end 1997 through 2002, reflecting the Company's goal of creating long-term shareholder value.

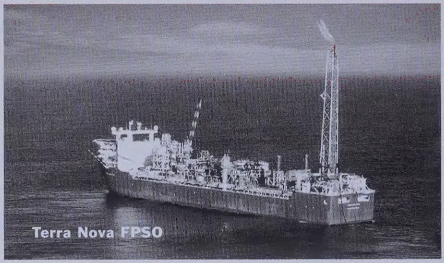


(December 31, 1997 = 100)
Changes in yearly closing values for Petro-Canada shares compared with the Toronto Stock Exchange (S&P/TSX Composite Index), the TSX Integrated Oils sub-index and the TSX Oil & Gas Producers sub-index.

CORE BUSINESSES AT A GLANCE

PETRO-CANADA IS STRATEGICALLY FOCUSED ON FIVE CORE BUSINESSES:

EAST COAST OIL



Terra Nova FPSO

BUSINESS DESCRIPTION

> Explores for, develops, produces and markets oil from offshore Newfoundland
> 20% interest in the Hibernia oil field
> 34% interest in, and operator of, the Terra Nova oil field
> 27.5% interest in the White Rose oil field currently under development
> Interests in other significant discoveries and exploration acreage

STRATEGIES

> Expand light oil production base from offshore Newfoundland, capitalizing on experience gained in developing the Hibernia and Terra Nova oil fields
> Pursue high-potential exploration plays

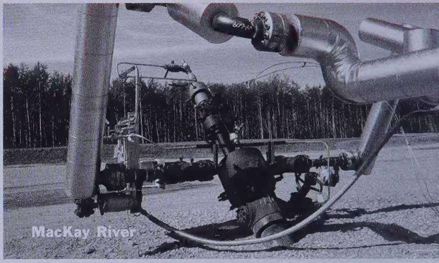
2002 ACHIEVEMENTS

> Terra Nova Floating Production Storage and Offloading (FPSO) vessel commissioned with first oil shipped late January 2002. Petro-Canada's share of production for the year averaged 35 800 barrels per day
> Terra Nova achieved 86% average operating time during first year of operation in a challenging environment
> Strong operating performance at Terra Nova and Hibernia increased Petro-Canada's share of production to a record 71 900 barrels per day
> Achieved regulatory approval to produce an average of 150 000 barrels per day from Terra Nova
> Successfully drilled eight new wells at Hibernia and five at Terra Nova
> Sanctioned the White Rose development. First oil is targeted for the fourth quarter of 2005

PLANS FOR 2003

> Increase East Coast conventional crude oil production to an average of 79 000 barrels per day net to Petro-Canada
> Evaluate Terra Nova Far East economic potential
> Maintain on schedule and on budget performance at White Rose
> In February 2003, commenced drilling first of two deepwater exploration wells in the Flemish Pass region located almost 500 km northeast of St. John's, Newfoundland

OIL SANDS



MacKay River

BUSINESS DESCRIPTION

> 12% working interest in the Syncrude oil sands mining operation
> 100% working interest in the MacKay River *in situ* oil sands operation
> Interests in about 300 000 net acres of prospective *in situ* oil sands leases
> Evaluating feed conversion potential at the Edmonton refinery to integrate *in situ* production with refining

STRATEGIES

> Increase share of Syncrude production capacity to over 43 000 barrels per day by 2005 and participate in further expansions
> Phased development of oil sands properties to benefit from learnings and respond to evolving market conditions
> Pursue *in situ* oil sands developments and integration with our Edmonton refinery

2002 ACHIEVEMENTS

> MacKay River *in situ* bitumen project completed on schedule and on budget. Project commenced steaming of the reservoir in September, and first production was achieved in November from the first set of 25 well pairs. December production averaged 9 400 barrels per day
> Continued with third phase of Syncrude expansion. Petro-Canada's share of Syncrude production averaged 27 500 barrels per day
> Commenced third-party construction of a 165 megawatt MacKay River co-generation plant
> Advanced regulatory applications for the 80 000 barrels per day Meadow Creek *in situ* project and for feed conversion at the Edmonton refinery

PLANS FOR 2003

> Continue to participate in Syncrude Stage 3 expansion (upgrader expansion and second train at Aurora Mine)
> Increase MacKay River production to reach design rate of 30 000 barrels per day by year-end
> Sanction Meadow Creek and refinery conversion projects by year-end, pending regulatory approval and satisfactory project economics, particularly with respect to the impacts of the Kyoto Protocol

NORTH AMERICAN NATURAL GAS

Foothills exploration

BUSINESS DESCRIPTION

- Explores for, produces and markets natural gas and associated liquids
- Among the largest producers in Western Canada
- Exploring in the Alberta Foothills, northeastern British Columbia, Mackenzie Delta, offshore Nova Scotia and Alaska

STRATEGIES

- Maximize profitability in Western Canada through focused exploration and development in our core areas – the Alberta Foothills, northeastern British Columbia, and southeastern Alberta
- Pursue high-potential exploration plays in the Mackenzie Delta, offshore Nova Scotia and Alaska

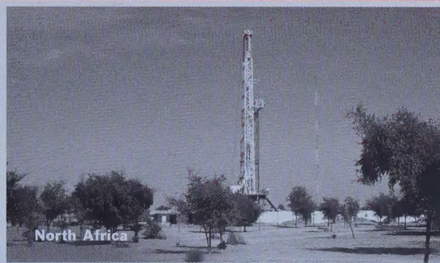
2002 ACHIEVEMENTS

- Gas production averaged 722 million cubic feet per day
- Crude oil and natural gas liquids production in Western Canada averaged 18 900 barrels per day
- Added 247 billion cubic feet equivalent of proved reserves, replacing 86 per cent of 2002 gas and NGL production
- Achieved three-year average finding and development costs of $1.39 per thousand cubic feet of gas equivalent
- Significant natural gas discovery at Tuk M-18 well in the Mackenzie Delta
- Acquired additional exploration acreage in Alaska with geological characteristics similar to the Alberta Foothills

PLANS FOR 2003

- Maintain active drilling programs in the Alberta Foothills, northeastern British Columbia, and southeastern Alberta
- Drill at least one exploration well in the Mackenzie Delta
- Pursue prospect identification on Alaskan acreage
- Acquire seismic data for Scotian Slope exploration acreage

INTERNATIONAL



North Africa

BUSINESS DESCRIPTION

- On May 2, 2002, Petro-Canada acquired the upstream businesses of Veba Oil & Gas, a European-based exploration and production company, establishing International as our fifth core business and a platform for long-term growth
- Production and exploration interests are focused in three regions: Northwest Europe, North Africa/Near East, and Northern Latin America

STRATEGIES

- Focus on profitable growth over the longer term by exploiting the existing reserve base and pursuing a balance of new exploration and development opportunities in core areas, including asset acquisitions

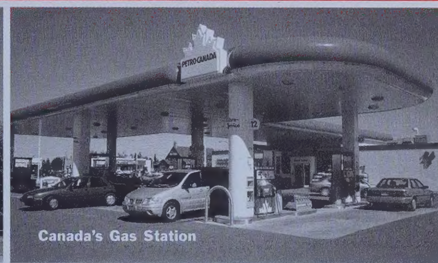
2002 ACHIEVEMENTS

- Early closing of the Veba acquisition and smooth integration of the business into Petro-Canada
- Drilling of a successful appraisal well on the Clapham discovery in the U.K. North Sea and government approval of the development plan
- Discovery of gas offshore Netherlands at L5b and government approval of the field's development plan
- Start of offshore gas production and liquefaction in Trinidad, with average daily production built to 41 million cubic feet per day net to Petro-Canada
- Averaged over the full year, production equated to 142 700 barrels of oil equivalent per day

PLANS FOR 2003

- Progress Clapham field development including drilling of wells and installation of subsea facilities
- Development of offshore Netherlands gas block to come on stream early 2004
- Continue evaluation for commercial development of discovered hydrocarbon resources at La Ceiba in Venezuela
- Increase production in Trinidad to 60 mmcf/d by mid 2003 when the third Atlantic LNG production train comes on stream
- Invest in existing assets, in particular for improved oil recovery
- Seek medium- and long-term growth opportunities
- Maintain current production levels

DOWNSTREAM



Canada's Gas Station

BUSINESS DESCRIPTION

- Converts crude oil into refined products, including gasoline, diesel, lubricants and asphalt
- Operates three refineries, representing 17% of Canada's refining capacity
- Markets refined petroleum products and services through a nationwide network of retail and wholesale outlets
- Canada's second largest marketer of refined petroleum products with a 17% share of market
- Manufactures and markets high-quality specialty lubricants

STRATEGIES

- Generate superior returns by focusing on first-quartile refining performance, building on our strength in niche markets, being the brand of choice for Canadian gasoline consumers, and increasing sales of high-margin specialty lubricants

2002 ACHIEVEMENTS

2002 CONVENIENCE STORE CHAIN OF THE YEAR

- Petro-Canada's convenience stores won the 2002 Chain of the Year Award from leading U.S. trade publication *Convenience Store Decisions* magazine, becoming the first Canadian company and the first non-U.S. retailer to win the coveted award
- Continued growth of new-image retail sites increased convenience store sales and margins by more than 30% each
- Achieved throughput per retail site of 4.1 million litres
- Total sales of refined products increased to a record 55.7 million litres per day
- Asphalt sales reached a record 1.6 billion litres
- Achieved refinery utilization of 101% reflecting continued reliable operations
- Increased sales of high-margin lubricants by 10% with penetration into new high-value automotive applications

PLANS FOR 2003

- Continue to narrow the gap on first-quartile refining performance, and improve on the solid refinery reliability and utilization of 2002
- Continue refinery modifications to meet future environmental regulations for fuels
- Continue the roll-out of new-image retail sites and deliver increased sales of non-petroleum products and services
- Further increase lubricant sales into higher-margin markets

TO OUR SHAREHOLDERS

"We remain focused on ensuring strong profitability in the base businesses while continuing to build a platform for growth, setting the stage for an exciting future for Petro-Canada."

RON BRENNEMAN, *CHIEF EXECUTIVE OFFICER*

I am pleased to report that 2002 was an exceptional year for Petro-Canada. We doubled production, we completed a major international acquisition and we retired half a billion dollars in debt. But more importantly, we executed our strategy successfully on all fronts. This exceptional operating performance combined with a favourable commodity price environment to produce excellent financial results for the year. We remain focused on ensuring strong profitability in the base businesses while continuing to build a platform for growth, setting the stage for an exciting future for Petro-Canada.

EXCEPTIONAL OPERATING PERFORMANCE

We had several milestone events in 2002 – the Veba acquisition, the Terra Nova start-up, the MacKay River start-up – in addition to our less glamorous but equally important successes in continuing to improve the profitability of our Western Canada natural gas and Downstream businesses.

I am especially pleased with the progress in our Downstream business, where we delivered strong results in spite of a difficult business environment of rising crude prices and weak margins. Maximizing plant reliability, high-grading the lubricant sales mix and growing sales while reducing operating costs are key elements of our drive towards first quartile performance. Highlights in 2002 included retail fuel sales growth that outpaced the industry as a whole, and a remarkable 30 per cent increase in non-petroleum sales at our retail convenience stores. To cap it off, our retail business won the Chain of the Year award for the quality of offering and the excellent service across our network. This is the first time a non-U.S. company has won this award, so our people are justifiably proud of this accomplishment.

In the Upstream, our Western Canada natural gas business continued to outperform in a very competitive and maturing basin. Industry discoveries are decreasing in size and production from the basin reportedly declined for the first time in many years. Reflecting that maturity, Petro-Canada's reserves replacement fell below 100 per cent. Nevertheless, our finding and development costs remained very competitive, again making us one of the most profitable producers in the basin. We look to the Mackenzie Delta, Scotian Slope and Alaska for our future growth in North American gas as the Western Canada Basin continues to mature.

In our East Coast Oil business, 2002 was a year of exceptional growth as production more than doubled. The year began with a world-class start-up for Terra Nova with its rapid ramp-up to full production and excellent first-year reliability. Both Terra Nova and Hibernia exceeded our production expectations for the year. The next development, White Rose, got underway with the awarding of key contracts.

We also saw growth in our Oil Sands business. We celebrated the on-time and on-budget start-up of MacKay River, our first *in situ* oil sands project. MacKay River is the first stage of Petro-Canada's integrated oil sands strategy, which would see bitumen produced from a number of *in situ* projects and upgraded at our Edmonton Refinery through a series of developments spanning the next decade.

While the federal government's ratification of the Kyoto Protocol represents a challenge for oil sands development, Petro-Canada is working closely with the government to clarify key aspects of the Kyoto implementation plan. Some assurance has been given to the industry to limit the cost exposure for existing operations. But the application of climate change measures to new, longer-term projects is still unclear and will be critical to the decision to proceed.

Reliability and unit costs at Syncrude improved in the last half of the year, following a major planned shutdown for maintenance. Some issues remain with the Aurora mine reliability, but Syncrude management is committed to resolving these to support sustainable performance as demonstrated in late 2002.

A NEW PLATFORM FOR GROWTH

The most significant event of the year for Petro-Canada was the acquisition and integration of the upstream businesses of Veba Oil & Gas, creating a new core international business for Petro-Canada. As we were already represented in all the major oil and gas basins across Canada, we had been seeking a very specific type of opportunity to step out internationally and we found a particularly good fit with this acquisition. We are seeing immediate results, as our International business contributed 25 per cent of the Company's operating earnings in the last half of 2002. We are very pleased with both the quality of the acquired assets and the capability of the organization. We have now largely completed the integration effort and are turning our attention to identifying opportunities for long-term growth. And because of our outstanding financial results last year, we have already been able to pay down 25 per cent of the debt taken on to finance the acquisition. So our balance sheet strength has essentially been restored to target levels.

To conclude the Upstream story, successful execution of our strategies has laid the foundation for strong future growth. This is demonstrated by our reserves position at the end of 2002. Petro-Canada's total reserves – proved, probable and possible – rose to 4.2 billion barrels of oil equivalent, up 29 per cent from a year ago. Our future will be built on this expanded reserve base, and our track record demonstrates we can translate those reserves into profitable, sustained growth.

A WORLD-CLASS FUTURE

Our strategy and our ability to execute that strategy on all fronts establish the foundation for a tremendous future for Petro-Canada. Our goal is to create shareholder value over the long term by maintaining a profitable base business and capitalizing on our superb opportunities for growth, delivering results through disciplined execution. As always, we will maintain our firm commitment to environmental responsibility, integrity, community investment and employee well-being. We take great pride in Petro-Canada's excellent reputation on these fronts.

ACCOUNTABILITY TO SHAREHOLDERS

Considerable public attention has been drawn recently to the subject of corporate accountability. Petro-Canada has always maintained the highest standards and practices in corporate governance and we were pleased to see that confirmed in recent third party rankings where Board independence and accountability were cited as key strengths. Our Management Proxy Circular this year has more information on corporate governance and the role of our Board of Directors, including a scorecard against the TSX governance guidelines.

PEOPLE CREATING ENERGY

On behalf of the Executive Leadership Team, I would like to recognize and commend Petro-Canada's employees, who are proving their capability and their commitment in successfully executing our strategy. I am also pleased to extend a warm welcome to the 300 new employees in our International business unit.

On behalf of my fellow Board members and management, I would like to convey our sincere thanks to Director Purdy Crawford, who will retire from the Board at our Annual Meeting. The depth of his experience and wisdom was of immense value to the Corporation and to the Board.

I am proud that we delivered on what we said we would during 2002. As we move through 2003, I am confident we will continue on that path.

Ron Brenneman
Chief Executive Officer

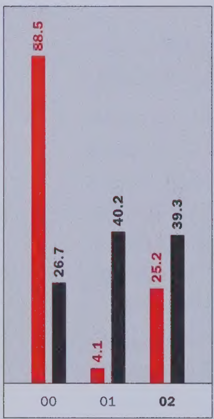
MANAGEMENT'S DISCUSSION & ANALYSIS

Management's Discussion and Analysis (MD&A) should be read in conjunction with the Financial Statements and Notes included in this annual report. Graphs accompanying the text identify our 'value drivers', key measures of performance in each component of our business.

RESULTS OF OPERATIONS

Shareholder Value

Shareholder value grew 25.2 per cent through share price appreciation and dividends.



- One-year return *(per cent)*
- Three-year average return *(per cent)*
- Shareholder value measures the change in the Petro-Canada share price plus dividend returns.

Summarized Financial Results

Consolidated Financial Results

(millions of dollars, unless otherwise indicated)	**2002**	2001[1]	2000[1]
Earnings from operations[2]	**$ 1 024**	$ 912	$ 879
Loss on foreign currency translation	**(52)**	(96)	(53)
Gain on disposal of assets	**2**	30	71
Reorganization costs	**–**	–	(38)
Net earnings	**$ 974**	$ 846	$ 859
Earnings per share *(dollars)* – basic	**$ 3.71**	$ 3.19	$ 3.15
– diluted	**3.67**	3.16	3.13
Cash flow[3]	**2 276**	1 688	1 870
Cash flow per share *(dollars)*	**8.66**	6.37	6.87
Debt	**3 057**	1 401	1 774
Cash and short-term investments	**234**	781	1 415
Average capital employed	**$ 7 826**	$ 6 259	$ 5 883
Return on capital employed *(per cent)*	**13.9**	14.8	16.0
Operating return on capital employed[2] *(per cent)*	**14.5**	15.8	16.4
Return on equity *(per cent)*	**18.3**	18.1	20.7

1 Effective January 1, 2002 the Company adopted, retroactively, the recommendations of the Canadian Institute of Chartered Accountants on accounting for foreign currency translation of long-term debt and, as a result, prior year comparative figures have been restated to conform with the current year's presentation.
2 Earnings from operations are earnings before gains or losses on foreign currency translation and on disposal of assets. In 2000, earnings from operations are before reorganization costs.
3 Before changes in non-cash working capital items.

This MD&A contains forward-looking statements, including, but not limited to, references to: future capital and other expenditures (including the amount, nature and sources of funding thereof); oil and gas production levels and the sources of their growth; tax and royalty rates; oil and gas prices; the Canadian dollar exchange rate; interest rates; refining and marketing margins; demand for refined petroleum products; planned facilities construction and expansion; retail site throughputs; pre-production and operating costs; reserve estimates; reserves life; natural gas export capacity; plans for and results of exploration and development activities; environmental matters; drilling plans; acquisition and disposition of resource properties; and the dates by which certain areas and facilities will be developed or will come on-stream. Undue reliance should not be placed on these forward-looking statements, which are based upon Petro-Canada's assumptions and are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; refining and marketing margins; the ability to produce and transport crude oil and natural gas to markets; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates and interest rates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; changes in environmental and other regulations; the availability of capital markets; risks attendant with oil and gas operations; and other factors, many of which are beyond the control of Petro-Canada. Petro-Canada undertakes no obligation to update publicly or revise any forward-looking statements contained herein, and such statements are expressly qualified by this cautionary statement.

2002 COMPARED WITH 2001

Earnings from operations climbed 12 per cent to a record $1 024 million in 2002. The improvement reflected a substantial increase in Upstream earnings, with partial offsets from a decline in the Downstream and an increase in the net cost of Shared Services. Net earnings and cash flow also climbed to record levels in 2002, reflecting the impact of Petro-Canada's new Upstream International segment, established following the acquisition of most of the oil and gas businesses of Veba Oil & Gas GmbH on May 2, 2002. This new business contributed $225 million to earnings in 2002. The record cash flow includes contributions of $1 417 million from Upstream Canada and $583 million from Upstream International. A $431 million increase in the current portion of the provision for income taxes, affecting cash flow, was largely related to Upstream International business operations.

While return on equity improved to 18.3 per cent from 18.1 in 2001, the operating return on capital employed declined to 14.5 per cent from 15.8, reflecting a weaker business environment and additional investment for future upstream growth.

Business Conditions

Economic factors influencing Petro-Canada's Upstream financial performance include crude oil and natural gas prices as well as the Canadian/U.S. dollar and Canadian dollar/euro exchange rates. Prices for energy commodities are primarily affected by supply and demand, weather, political events and the level of industry inventories.

Factors influencing Downstream performance include the level and volatility of crude oil prices, industry refining margins, movements in light/heavy crude oil price differentials, demand for refined petroleum products and the degree of market competition.

BUSINESS CONDITIONS IN 2002

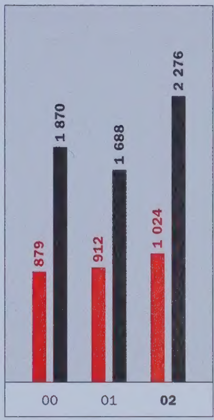
The evolution of oil prices in 2002 was again marked by major swings in response to changes in market fundamentals as well as political developments with a major bearing on global oil markets. Major political developments having a significant influence on oil prices in 2002 included the persistent threat of war with Iraq and, late in the year, political instability in Venezuela.

The evolution of North American natural gas prices was also subject to considerable volatility. The combination of softening demand and production growth during 2001 resulted in a massive build-up of working gas in storage as we entered the 2001/02 winter season. The year 2002 started with abundant gas in storage and warmer-than-normal winter conditions prevailed across the continent. This led to substantially weaker prices than those that characterized the 2000/2001 winter season and provided little opportunity for any significant strengthening in prices until the onset of winter weather late in the year.

Sales of Canadian refined petroleum products increased in 2002 by approximately 0.8 per cent compared with a decline of 1.0 per cent in 2001. For most of 2002, refining margins were softer and light/heavy oil price differentials were narrower than in the previous year.

Earnings from Operations and Cash Flow

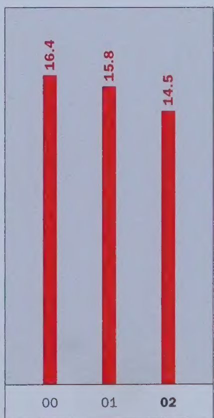
Earnings from operations topped $1 billion in 2002.



- Earnings from operations *($ millions)*
- Cash flow *($ millions)*
- Earnings from operations do not include gains or losses on foreign currency translation and on disposal of assets. In 2000, earnings from operations are before reorganization costs.

Operating Return on Capital Employed

Operating return on capital employed reflected a weaker business environment and additional investment for future upstream growth.



- Operating return on capital employed *(per cent)*
- Earnings from operations do not include gains or losses on foreign currency translation and on disposal of assets. In 2000, earnings from operations are before reorganization costs.

Commodity Price Indicators and Exchange Rates

(averages for the years indicated)

	2002	2001
Crude oil price indicators (per barrel):		
North Sea Brent	**US$ 24.98**	US$ 24.46
West Texas Intermediate (WTI) at Cushing	**US$ 26.08**	US$ 25.90
WTI/Brent price differential	**US$ 1.10**	US$ 1.44
Brent/Maya price differential	**US$ 4.08**	US$ 7.31
Edmonton Light	**Cdn$ 40.41**	Cdn$ 39.58
Edmonton Light/Bow River (heavy) price differential	**Cdn$ 8.90**	Cdn$ 14.97
Natural gas price indicators:		
At Henry Hub – per million British thermal units (mmbtu)	**US$ 3.25**	US$ 4.38
AECO spot – per thousand cubic feet (mcf)	**Cdn$ 4.24**	Cdn$ 6.57
Henry Hub-AECO-C basis differential – per mmbtu	**US$ 0.66**	US$ 0.27
New York Harbor 3-2-1 refinery crack spread – per barrel	**US$ 3.36**	US$ 4.44
Exchange rates – US$ per Cdn$	**US$ 0.637**	US$ 0.646
– euro per Cdn$	**euro 0.674**	euro 0.721

Although business conditions are expected to remain volatile in 2003, Petro-Canada's business is managed for the long term.

OUTLOOK FOR BUSINESS CONDITIONS IN 2003

The global energy outlook in 2003 remains clouded by the uncertainties arising from a delayed global economic recovery and, at time of writing, the continuing threat of a U.S.-led military intervention in Iraq and the political crisis in Venezuela. Given these conditions, Petro-Canada expects volatility in oil prices to continue through 2003. Given current low levels of crude oil stocks globally, worries about potential supply disruptions arising from a war in Iraq and from political instability in Venezuela will continue to dominate the behaviour of oil prices during the first half of the year and possibly beyond. These concerns are being reinforced by doubts about OPEC's ability to make up for the potential loss of Venezuelan and Iraqi barrels.

In North America, the energy outlook during 2003 is complicated further by the rapid tightening of the natural gas supply/demand balance, due to unseasonably cold winter weather in key consuming markets at a time of a very poor supply performance across the continent. This has led to much faster rates of gas withdrawals from storage than anticipated. If, as a consequence, the heating season closes with low levels of natural gas inventories, there will be increased need for gas injections to replenish storage levels before next winter. Thus, natural gas prices across North America are expected to remain strong but highly volatile in 2003 as the rapid depletion of natural gas in storage reduces the ability of inventories to cushion unexpected swings in supply and/or demand. Moreover, the continuing weak outlook for production growth in 2003, due to the maturity of traditional basins in the United States and the Western Canada Sedimentary Basin, will continue to provide support to gas prices during the remainder of the year.

Only a modest improvement in the volume of domestic sales of refined products and refinery margins is anticipated for 2003, as external business conditions that have a major influence on downstream operations are expected to remain more or less similar to those that prevailed in 2002.

ECONOMIC SENSITIVITIES

The following table shows the estimated after-tax effects that changes in certain factors would have had on Petro-Canada's 2002 net earnings had these changes occurred. We base these calculations on business conditions, production and sales volumes realized in 2002.

Sensitivities Affecting Net Earnings

Factor	2002 Averages	Change (+/-)	Approximate Change (+/-) in Net Earnings [1]
			(millions of Canadian dollars)
Total Upstream			
Price received for crude oil and liquids	$38.50/bbl	Cdn$1.00/bbl [2]	34
Price received for natural gas	$4.07/mcf	$0.25/mcf	38
Production of crude oil and liquids	244 900 barrels per day (b/d)	1 000 b/d	4
Production of natural gas available for sale	825 million cubic feet per day (mmcf/d)	10 mmcf/d	3
Downstream			
New York Harbor 3-2-1 crack spread [3]	US$3.36/bbl	US$0.10/bbl	5
Light/heavy crude price differential [4]	$8.90/bbl	$1.00/bbl	13
Corporate			
Exchange rate: US$ per Cdn$ [5]	US$0.637	US$0.01	(9)

1 The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any inter-relationship among the factors. The application of these factors may not necessarily lead to an accurate prediction of future results of operations. We may undertake risk management initiatives from time to time that affect these sensitivities.

2 This sensitivity is based upon an equivalent change in the price of WTI and North Sea Brent. In 2002 WTI averaged US$26.08/bbl and North Sea Brent averaged US$24.98/bbl.

3 New York Harbor 3-2-1 crack spread applies mainly to Eastern Canada markets.

4 The spread between the prices of benchmark Edmonton Light and Bow River (heavy) crude oils.

5 A strengthening Canadian dollar versus the U.S. dollar has a negative effect on Petro-Canada's earnings.

Upstream

Petro-Canada's Upstream operations are diversified both in resource type and geographically. In Canada, we have three Upstream core businesses: East Coast offshore oil; Oil Sands in northeastern Alberta; and North American natural gas, with current production in Western Canada. Internationally, as a result of a major acquisition of oil and gas assets in 2002, we are active in three core areas: Northwest Europe; North Africa/Near East; and Northern Latin America.

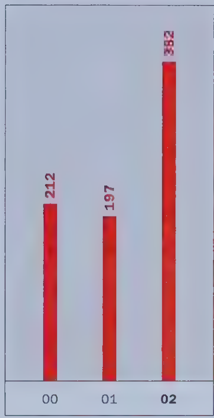
Petro-Canada's portfolio offers a platform for long-term growth in crude oil and natural gas. Our goal is superior profitability and profitable growth. Our strategy combines a drive for first quartile operating performance with a strict discipline as to where and how we invest.

In 2002, Petro-Canada's Upstream operating return on capital employed was 17.6 per cent, down from 20.9 per cent in 2001, reflecting lower natural gas prices and additional investment for future growth in Canada and internationally.

Total Upstream production in 2002 consisted of an average 244 900 b/d of oil and liquids and 825 mmcf/d of natural gas, or a record 382 400 barrels of oil equivalent per day (boe/d), almost double the 196 500 boe/d achieved in 2001. (Natural gas is converted at the rate of 6 000 cubic feet to one barrel of oil equivalent). The contribution to 2002 production from Upstream Canada averaged 239 700 boe/d and from Upstream International 142 700 boe/d. At 2002 year-end, proved reserves totalled 1 290 million boe (mmboe), up 57 per cent from a year earlier. The impact of the newly-acquired international assets combined with additions from drilling at Hibernia and Terra Nova and development of Syncrude's Aurora Mine more than offset production in the year. During 2002, independent petroleum reservoir engineering consultants Sproule Associates Limited and DeGolyer and MacNaughton conducted evaluations, technical audits and reviews of Petro-Canada's hydrocarbon reserves. Based on the results of this work, we conclude that the Company's year-end 2002 reserves estimates are reasonable. In addition, PricewaterhouseCoopers LLP, as contract internal auditor, tested the non-engineering management control processes used in establishing Canadian reserves.

Oil and Gas Production

Production increased due to the international acquisition, the start-up of Terra Nova and higher volumes from Hibernia.



■ Upstream production
(thousands of barrels of oil equivalent per day)

Petro-Canada's production of oil and gas nearly doubled in 2002 to a record 382 400 barrels of oil equivalent per day.

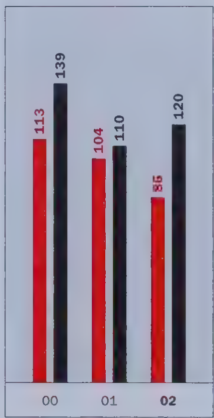
Upstream Canada

Upstream Canada Financial Results

(millions of dollars)	**2002**	2001	2000
Earnings from operations	**$ 689**	$ 690	$ 685
(Loss) gain on sale of assets	**(1)**	29	113
Net earnings	**$ 688**	$ 719	$ 798
Cash flow	**$ 1 417**	$ 1 125	$ 1 460
Expenditures on property, plant and equipment and exploration	**$ 1 281**	$ 1 131	$ 884
Total assets	**$ 5 922**	$ 5 118	$ 4 811

Reserves Replacement

Total conventional oil and gas reserves replacement increased in 2002.



■ Natural gas and associated liquids *(per cent)*

■ Total conventional oil and gas *(per cent)*

– Excludes acquisitions and divestitures.

– Excludes Syncrude and MacKay River.

2002 COMPARED WITH 2001

Earnings from operations in 2002 were virtually unchanged from the previous year, as a $251 million increase in operating revenues combined with a $19 million decrease in income taxes was offset by a $48 million increase in operating costs, a $140 million increase in depreciation, depletion and amortization expense and a $52 million rise in exploration expense. The revenue gain reflected increased East Coast crude oil production, with a partial offset from lower prices for natural gas. Total crude oil and natural gas liquids production from Canadian operations in 2002 averaged 119 400 b/d, up 59 per cent from 75 100 b/d in 2001, with the increase resulting from the start-up of Terra Nova, averaging 35 800 b/d, and a 6 400 b/d improvement at Hibernia. Natural gas production averaged 722 mmcf/d, up from 714 mmcf/d in 2001. The average price received for Upstream Canada crude oil and other liquids production was $37.95/bbl in 2002, compared with $37.24/bbl a year earlier. Canadian natural gas prices averaged $4.01/mcf, down from $6.00/mcf in the previous year. The increases in operating costs and depreciation, depletion and amortization expense mainly reflect the start-up of Terra Nova. The rise in exploration expense was due

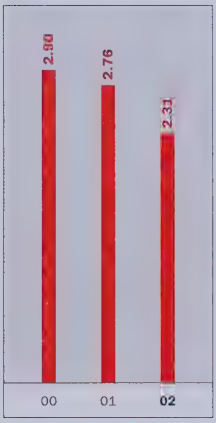
2002 began with the world-class start-up of Terra Nova. Both Terra Nova and Hibernia exceeded production expectations.

in large part to increased drilling in the Mackenzie Delta and the Scotian Slope. Current income taxes, affecting cash flow, decreased $88 million from the prior year. The decrease relates in part to net deferrals of current income taxes, mainly related to earnings of the Petro-Canada Oil and Gas partnership. The deferrals increased current taxes by about $50 million in 2002 compared to an increase of about $100 million in 2001.

Upstream Canada Review & Outlook

Hibernia Operating and Overhead Costs

Operating and overhead costs per barrel continued to decline.



■ Unit operating and overhead costs *($ per barrel)*

EAST COAST OIL

Strategy

> Continue to profitably add reserves and production through the development of White Rose and field extensions at Terra Nova and Hibernia.

> Pursue exploration opportunities in the largely unexplored deeper waters off the Grand Banks.

Executing the strategy

Our share of East Coast oil production more than doubled to 71 900 b/d in 2002 as a result of production start-up at Terra Nova and solid gains at Hibernia. Terra Nova came on stream January 20, 2002, and the performance of the production system was outstanding throughout the first year of operation. Production uptime, including a planned three-week maintenance shutdown, was 86 per cent, exceptional for a start-up year. As a result, production for the year averaged 105 400 b/d (35 800 b/d net to Petro-Canada), well above planned volumes. Operating costs in 2002, averaging $4.25/bbl, are not a good indicator of costs going forward, as they are founded on a build-up of production volumes over less than a full year of operations and one-time start-up costs, as well as the three-week maintenance shutdown. In 2003, we expect to reduce operating costs to below $2.70/bbl. Field activity at Terra Nova in 2002 included the drilling of five production and injection wells.

Production from Hibernia in 2002 rose to a new record of 180 500 b/d (36 100 b/d net to Petro-Canada), up from 148 500 b/d (29 700 b/d net to Petro-Canada) in the previous year, despite a two-week planned maintenance shutdown of the production platform. Operating costs in 2002 averaged $2.16/bbl, down from $2.62/bbl in 2001, with the per-unit improvement driven mainly by the volume gain. Drilling in 2002 added eight wells.

Further strengthening our position on the East Coast in 2002, we began development of the White Rose oil field (Petro-Canada – 27.5 per cent interest). The project includes construction of a Floating Production Storage and Offloading vessel (FPSO) with a production capacity of 100 000 barrels of oil per day and a subsea production system. Field development plans anticipate 19 to 21 wells to recover an estimated 200 million to 250 million barrels of oil. Our Terra Nova experience has been incorporated into White Rose planning, reducing risk and uncertainty. Petro-Canada's estimate of the project's gross pre-production cost, including the first 10 wells, is $2.3 billion.

Outlook

2003 Production expectations:

> East Coast conventional crude oil production to average 79 000 b/d.

Growth plans:

> Extend the production plateau at both Hibernia and Terra Nova.

> Complete White Rose development by late 2005.

> Test the exploration potential of the Flemish Pass.

2003 Capital spending plans:

> $170 million for development of the White Rose project.

> $140 million for ongoing Hibernia and Terra Nova drilling and development programs.

> $40 million for exploratory drilling.

In addition to development of White Rose, our Grand Banks mid-term growth focus includes extensions to existing reservoirs and evaluation of potential subsea tiebacks of smaller discoveries and prospects to the Hibernia and Terra Nova facilities. While the Hibernia reservoir currently provides most of the reserves and production for the Hibernia project, significant reserves potential also exists in the Ben Nevis Avalon formation. The reservoir quality of these sandstones does not match that of the prolific Hibernia reservoir but a substantial portion may be economically accessible. Results of an appraisal well drilled in late 2002 to test the extent of the Ben Nevis Avalon structure continue to be evaluated and further appraisal drilling may be required. At Terra Nova, where development is currently focused on the Graben and East Flank segments of the reservoir, we are continuing to assess the potential of the adjacent Far East block. A first Far East well, drilled in 2001, encountered 80 metres of oil-bearing net pay in the Jeanne d'Arc sands. Results of a second delineation well, completed in late 2002, are

being analysed. At least one delineation well is scheduled for 2003. Project plans for White Rose anticipate production start-up in late 2005 and a field life of 10 to 12 years, with peak annual average production of 90 000 b/d (24 700 b/d net to Petro-Canada) sustainable for about four years.

Our regional exploration work has identified a number of prospects in the Flemish Pass and Salar Basins. These two basins are located in average water depths of 1 100 and 1 500 metres, respectively, compared to water depths of less than 100 metres for the Jeanne d'Arc basin, where all major oil discoveries to date have been made. In early February 2003, we commenced drilling the Mizzen L-11 well (Petro-Canada – 33.34 per cent working interest) in the Flemish Pass region. It is the first of two wells planned for the region in 2003.

OIL SANDS

Strategy

> Continue reliability improvements and pursue profitable long-term growth from expansion of Syncrude.

> Capture the full value of *in situ* bitumen production through staged development integrated with our Edmonton refinery.

Executing the strategy

The successful completion in 2002 of our 100 per cent owned, 30 000 b/d, MacKay River *in situ* development, on schedule and on budget, was a significant milestone in our long-term oil sands plans. Start-up began late in the third quarter with initial steaming of the reservoir, followed by first bitumen production in November. Petro-Canada expects production to climb from an average 9 400 b/d in December 2002 to plant capacity of 30 000 b/d by the end of 2003. We believe we can sustain production at capacity for 25 years. The MacKay River production process uses steam-assisted gravity drainage (SAGD), a technology Petro-Canada helped to develop, which can economically recover over 60 per cent of the bitumen in place. SAGD combines horizontal drilling with thermal steam injection. Steam is injected into the reservoir through the top well of a horizontal well pair to mobilize the bitumen, which flows to the lower producing well. Initial development at MacKay River includes 25 horizontal well pairs. The water used to generate steam comes from underground, with more than 90 per cent recycled – a key feature of the facility's environmental efficiency. Total capital expenditures at MacKay River came in at $274 million.

With the knowledge gained from participation in a SAGD pilot project at an adjacent test facility, our operating technical risks at MacKay River are minimized. The result is high capital efficiency, reservoir confidence and lower operating cost. On completion of a 165 megawatt co-generation facility currently being constructed by TransCanada Energy Limited, we expect MacKay River operating costs to average about $2.25 plus one mcf of gas per barrel, which will be at the lower end of heavy oil supply costs in Canada. The co-generation plant, planned for start-up late in 2003, will provide MacKay River with a long-term assured supply of low-cost power and steam and reduce related greenhouse gas emissions by about 50 per cent when compared to the equivalent steam and electricity produced without co-generation. The facility will be owned by TransCanada Energy but operated as part of the MacKay River project.

Petro-Canada's 12 per cent share of Syncrude, the world's largest oil sands mining operation, forms another cornerstone of our oil sands growth plans. In 2002, Petro-Canada's share of Syncrude production averaged 27 500 b/d, up from 26 800 b/d in 2001. Syncrude management is directing increased resources towards resolving outstanding reliability concerns in an effort to fully realize Syncrude's production potential, and reduce operating costs. Unit operating costs declined to $19.50/bbl in 2002 from $19.91/bbl in the previous year. An extended planned maintenance program in the summer of 2002 impacted unit costs.

Outlook

2003 Production expectations:

> Petro-Canada's share of Syncrude production to average 27 900 b/d.

> MacKay River bitumen production to average 22 000 b/d.

Growth plans:

> Continue participation in the expansion program at Syncrude.

> Develop our second *in situ* bitumen production project at Meadow Creek.

> Advance our development plans for a large-scale, fully integrated project linking the production and refining of bitumen.

2003 Capital spending plans:

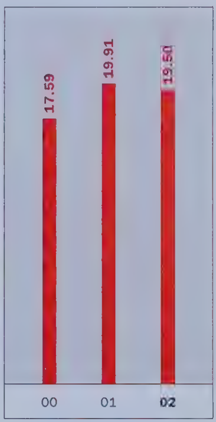
> $255 million for our share of Syncrude's expenditures.

> About $400 million for our proposed Edmonton refinery bitumen feed conversion and Meadow Creek development.

We celebrated the on-time and on-budget start-up of the MacKay River in situ oil sands project in 2002.

Syncrude Operating and Overhead Costs

Reliability of operations is being addressed.



■ Unit operating and overhead costs *($ per barrel)*

Petro-Canada continues to be one of the most profitable producers of natural gas in Western Canada, with strong performance in operating and finding & development costs.

At Syncrude, engineering and construction is currently underway on the third stage of a multi-stage expansion program. Stage 3 includes a second Aurora mine and an upgrading expansion. This stage is expected to increase production capacity by 100 000 b/d to a total of 360 000 b/d (over 43 000 b/d net to Petro-Canada) by 2005.

Over the next decade, assuming an appropriate regulatory climate concerning environmental issues including the Kyoto Protocol, we expect oil sands will be a major engine of growth for Petro-Canada. With interests in about 300 000 net acres of oil sands leases considered prospective for *in situ* development, we are well positioned to pursue this growth opportunity.

Completion of the MacKay River project was the first step in creating a large-scale, fully integrated bitumen production and refining operation. Our next step will be a second *in situ* development at Meadow Creek (owned 75 per cent by Petro-Canada), 45 kilometres south of Fort McMurray. Meadow Creek will have a bitumen production capacity of 80 000 b/d, more than twice that of MacKay River. Extensive seismic evaluation and delineation drilling on the property have confirmed significant bitumen resources. The property is well situated on existing infrastructure corridors. Development could begin by late 2004, with initial production by year-end 2007, giving us time to optimize the MacKay River development and incorporate our experience into the design and plans for Meadow Creek.

Timelines for start-up at Meadow Creek will be coordinated with the first phase of a major conversion to enable the Edmonton refinery to replace its existing light crude oil feedstock with bitumen. The initial conversion will provide upgrading and refining capability for about 85 000 b/d of bitumen. At a later date, we have plans for a third *in situ* development and a doubling of bitumen processing capacity at the Edmonton refinery. Complete implementation of our integrated oil sands strategy could take bitumen production to 170 000 b/d by 2012. Linkage of bitumen production with refining provides considerable insulation from heavy oil price fluctuations, eliminates bitumen marketing risks and provides Petro-Canada with a competitive advantage over non-integrated bitumen producers. Our staged approach to these capital-intensive projects will facilitate cost management, while allowing us to benefit from evolving technology.

Our application for the Meadow Creek development is under review. Regulatory approval for the feed conversion project at the Edmonton refinery is anticipated in early 2003. Decisions to proceed with these plans will only be made following regulatory approvals and continuing economic evaluations, particularly with respect to the impact of the federal government's Kyoto Protocol implementation plan. While both the federal and provincial governments have stated that the oil sands economic opportunity must be maintained, Petro-Canada is seeking further certainty as to the specifics of Kyoto Protocol implementation and its impact on economics.

NORTH AMERICAN NATURAL GAS

Strategy

> Maximize profitability through consistent top quartile performance in finding and development costs and in the efficient operation of our production facilities.
> For longer term growth, pursue high potential exploration in the Mackenzie Delta, offshore Nova Scotia and Alaska.

Executing the strategy

Natural gas production averaged 722 mmcf/d in 2002, up from 714 mmcf/d in 2001, as additional volumes from ongoing development and reduced gas plant turnarounds more than offset natural declines. Natural gas price realizations averaged $4.01/mcf, down 33 per cent from the previous year, due to soft market conditions for a large part of the year. Our conventional crude oil and natural gas liquids production in Western Canada averaged 18 900 b/d, up from 18 600 b/d in 2001. Operating and overhead costs in 2002 were $0.57 per thousand cubic feet of gas equivalent (mcfe), down from $0.60/mcfe in the previous year, partly reflecting the reduced turnarounds.

Exploration and development drilling in Western Canada resulted in 351 successful wells, for a success rate of 93 per cent. At 2002 year-end, Petro-Canada's proved natural gas reserves in Western Canada totalled 2 181 bcf, compared with 2 228 bcf at the close of 2001. Proved crude oil and natural gas liquids reserves, at 55 million barrels, were up from 54 million barrels a year earlier. Exploration and development successes added 247 billion cubic feet equivalent (bcfe) of natural gas and associated liquids to proved reserves, replacing 86 per cent of 2002 production.

The shortfall from our target of full reserves replacement reflects our focus on profitability and the challenging environment for economic reserves additions in the increasingly mature Western Canada Sedimentary Basin. As a result of strict investment discipline, our three-year average finding and development cost for natural gas and associated liquids remained highly competitive at $1.39/mcfe.

The success of our natural gas business over the past several years has resulted from a strategy of exploitation within our three core areas – the Alberta Foothills, northeastern British Columbia and southeastern Alberta – especially in the Foothills, where we have developed a strong technical competency in finding, developing and operating deep sour gas. In the Wildcat Hills area alone, the application of this competency over the past five years has resulted in 50 successful wells and a more than 300 per cent increase in area production. Drilling successes in 2002 included the Wildcat Hills 8-32 well – our best well ever in this area. This vertical well has net pay of 194 metres and is on production at 20 mmcf/d.

In the shallow gas region of Medicine Hat in southern Alberta, we completed our first winter drilling program, which continued into the summer months and resulted in 271 gross (164 net) successful wells. Reflecting the success of this ongoing development program, production from the area rose to 68 mmcf/d late in the year.

For longer term growth, we are continuing to pursue frontier opportunities. In early 2002, an aggressive exploration program in the Mackenzie Delta was rewarded with a significant natural gas discovery. The Tuk M-18 well (Petro-Canada – 50 per cent interest) tested at restricted rates up to 30 mmcf/d, with sustained deliverability estimated at 60 to 80 mmcf/d. Recoverable gas from the field is estimated at 200 bcf to 300 bcf. Tuk M-18 was one of three wells drilled during the winter of 2001/02; the remaining two were dry and abandoned. Offshore Nova Scotia, we participated in the Newburn H-23 exploratory well (Petro-Canada – 43 per cent interest) on the Scotian Slope, only the fifth industry well to test this deep water play. The well found non-commercial quantities of gas.

In Alaska, where our focus is the foothills area north of the Brooks mountain range, a field geological study has confirmed that the geology and prospectivity of the area is similar to the Alberta Foothills, where Petro-Canada has developed considerable expertise and has had significant success finding gas. At year-end, we held 100 per cent interests in over 400 000 acres. While it is unlikely the region will be serviced by a pipeline for some time, Petro-Canada's acreage is close to a proposed pipeline route to southern markets.

Outlook

2003 Production expectations:

> Western Canada natural gas production to average 690 mmcf/d.

Growth plans:

> Continue pursuit of attractive prospects in the Western Canada Sedimentary Basin while focusing on profitability rather than volume gain.

> Advance exploration programs in the Mackenzie Delta, Scotian Slope and Alaska.

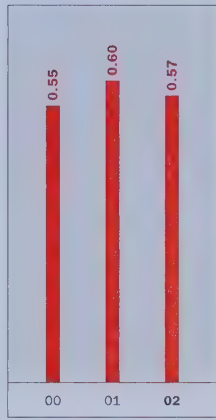
2003 Capital spending plans:

> Continue substantial funding with investment plans totalling $455 million, including drilling in the Western Canada Sedimentary Basin and in the Mackenzie Delta.

Our plans for the Mackenzie Delta in 2003 include at least one exploration well that will test the same trend where we had success with Tuk M-18. In January 2002, the Mackenzie Delta Producers Group, led by Imperial Oil Limited, completed preliminary feasibility studies on development of a Mackenzie Valley pipeline and began work on applications for regulatory approval. In July, the group called for non-binding nominations. Petro-Canada nominated 30 mmcf/d from its share of the Tuk gas pool. Given the long-term nature of Arctic development, as well as the anticipated lengthy regulatory review and approval process, a pipeline to southern markets is unlikely to be in place before the end of this decade. Our plans for offshore Nova Scotia include a 3-D seismic survey over additional licensed exploratory acreage, which could lead to an exploratory well in 2005.

Western Canada Operating and Overhead Costs

Costs per unit were down marginally from the previous year.



■ Unit operating and overhead costs *($ per thousand cubic feet of gas equivalent)*

– Includes Western Canada gas, conventional oil and liquids.

Natural Gas and Associated Liquids Finding and Development Costs in Western Canada

Finding and development costs remained competitive despite rising service and supply costs.

■ Natural gas *($ per thousand cubic feet of gas equivalent)*

– Three-year rolling average for proved reserves.

– Excludes acquisitions and divestitures.

Upstream International

Upstream International Financial Results

(millions of dollars)	2002	2001	2000
Earnings (loss) from operations	$ 225	$ (27)	$ 19
Loss on sale of assets	–	–	(41)
Net earnings (loss)	$ 225	$ (27)	$ (22)
Cash flow	$ 583	$ 27	$ 78
Expenditures on property, plant and equipment and exploration	$ 221	$ 153	$ 43
Total assets	$ 3 544	$ 186	$ 148

International is a new core business that contributed 25 per cent of Petro-Canada's operating earnings and cash flow in the second half of 2002.

The substantial improvement in financial performance in 2002 reflects the impact of a major acquisition, completed on May 2. In 2001, international operations were limited to modest activity in Algeria, Libya and Tunisia.

Averaged over the full year, production from International operations in 2002 equated to 142 700 boe/d. Production of crude oil and gas liquids averaged 125 500 b/d and natural gas 103 mmcf/d. Upstream International crude oil and liquids prices averaged $39.53/bbl and natural gas prices averaged $4.52/mcf.

Upstream International Review & Outlook

Strategy

> Exploit the existing reserve base and pursue new exploration and development opportunities, leveraging off existing relationships, skills and infrastructure.
> Establish a significant portfolio of growth opportunities, well balanced as to technical risk and economic return.

Executing the strategy

Petro-Canada gained a new platform for longer-term growth on May 2, 2002, with the acquisition of significant international oil and gas operations, while securing an immediate and substantial contribution to earnings. In addition to expanding our position in North Africa/Near East, a region of considerable underdeveloped potential, the new international properties provided Petro-Canada with solid footholds in the highly profitable North Sea and the highly prospective Northern Latin America region. Integration of the new operations was essentially completed prior to 2002 year-end. Rights of first refusal were exercised by third parties with respect to assets in Norway and Egypt.

From May 2 to December 31, 2002, production from the acquired assets averaged 210 000 boe/d, with performance boosted by completion of development projects in the United Kingdom and Trinidad.

Northwest Europe

In Northwest Europe, our production comes from the U.K. and Netherlands sectors of the North Sea, with exploration programs extending into Denmark and the Faroe Islands. In the U.K. sector, Petro-Canada's operations are centred around existing infrastructure, principally the Scott platform in the Outer Moray Firth and the Triton FPSO, located further south in the central North Sea, 190 kilometres east of Aberdeen. We hold interests in the Scott and Telford oil fields, the Guillemot West and Northwest oil fields, and the Bittern oil field. The Guillemot and Bittern fields are tied in to the Triton facilities. Production from the Netherlands sector includes natural gas from blocks L8b and L5c and oil from the Petro-Canada operated Hanze field. Over the last eight months of 2002, Petro-Canada's share of production from Northwest Europe averaged 40 500 b/d for crude oil and natural gas liquids and 89.5 mmcf/d for natural gas.

North Sea activity in 2002 included the tieback of a new subsea satellite at the western extension of the Guillemot West oil field to the Triton FPSO. This project, adding initial production of 18 000 barrels of oil per day net to Petro-Canada, typifies the profitable North Sea investment opportunities we are pursuing. Drilling results offering opportunities for development included a successful appraisal well at Clapham (Petro-Canada – 100 per cent working interest) in the U.K. North Sea and a gas discovery in block L5b (Petro-Canada – 30 per cent working interest) in the Netherlands.

North Africa/Near East

In the North Africa/Near East region, which provides the major portion of Petro-Canada's international production, our previously modest position in Algeria, Libya and Tunisia has been significantly expanded with the addition of new interests in Syria, Libya and Kazakhstan. In Syria, Petro-Canada's interests in three production sharing contracts are consolidated under the umbrella of a joint venture firm, Al Furat Petroleum Company (AFPC), which produces about 55 per cent of Syrian production. Our share of production for the period from May 2 to December 31, 2002 averaged 107 200 boe/d. With the emphasis on improved recovery from existing fields, AFPC has established a technical Study Centre dedicated to the integrated study of the latest technologies, including underbalanced drilling, 4-D seismic and high-resolution seismic stratigraphy.

In Libya, Petro-Canada is one of the largest producers and well positioned to play a significant role in the country's drive to expand reserves and production. Our major holding is a 49 per cent interest in a joint venture with the National Oil Company (NOC), which combines the operations of more than 20 fields. Our share of production over the last eight months of 2002 averaged 43 400 barrels of oil per day. Under a separate production sharing arrangement with NOC, development of two oil fields on the En Naga block was progressing towards completion at 2002 year-end. Production from this project (Petro-Canada working interest – 50 per cent) is expected to come on-stream in 2003 at an average annual rate of 6 800 b/d. Libya is a member of the Organization of the Petroleum Exporting Countries (OPEC). As such, production in that country may be constrained from time to time by OPEC quotas.

In Kazakhstan, initial production was achieved during the second half of 2002 from a small oil field development on the Temir licence (Petro-Canada – 40 per cent working interest). Early in 2003, following completion of a central production facility, we expect production to build to capacity of 12 000 b/d (4 800 b/d net to Petro-Canada).

Northern Latin America

Petro-Canada's interests in Northern Latin America are focused on natural gas in Trinidad and crude oil in Venezuela. In Trinidad, we hold a 17.3 per cent working interest in the North Coast Marine Area-1 (NCMA-1) offshore gas project. In August 2002, NCMA-1 achieved first production from initial development of the Hibiscus, Poinsettia and Chaconia natural gas fields. The 2002 program included commissioning the Hibiscus production platform and drilling of production wells. Our share of production from start-up to 2002 year-end averaged 32 mmcf/d. Production is delivered to the Atlantic LNG facility at Point Fortin for liquefaction and sale into United States markets.

Late in 2002, Petro-Canada completed the acquisition of a 50 per cent working interest in the La Ceiba block, which straddles the eastern shores of Lake Maracaibo in Venezuela. This property was initially excluded from the Veba acquisition pending resolution of pre-emptive rights. Commercial development of discoveries on the block continues to be evaluated. A right of first refusal concerning Veba's Cerro Negro heavy oil operations in Venezuela was still unresolved at year-end.

Our International acquisition establishes a platform for longer-term growth.

Outlook

2003 Production expectations:

> Total International production to average 210 000 boe/d.
> Northwest Europe to average 44 000 boe/d.
> North Africa/Near East to average 157 000 boe/d.
> Trinidad to average 48 mmcf/d.

Growth plans:

> In the North Sea, acquire resources adjacent to infrastructure.
> Advance opportunities to improve reserve recovery rates in Syria and Libya through the application of modern technology.
> Exploitation and concentric exploration in underdeveloped areas of Libya and Syria.
> Identify and develop growth opportunities in new areas.

2003 Capital spending plans:

> $260 million to sustain existing production.
> $190 million for new developments, including the Clapham project in the North Sea.
> $95 million for exploration opportunities.

In Northwest Europe, our key strategy is focused exploration and development on low-risk opportunities in the North Sea, centred on existing infrastructure. While the region is a mature play, even small developments are attractive. We are focusing on low-cost development of small and mid-size pools that can be rapidly brought into production. Our plans include expanding our presently modest exploration portfolio with the emphasis on securing licence operatorships or high working interests.

Our goal is to sustain profitable production over the medium term. The near-term focus includes development of a gas discovery on block L5b in the Netherlands sector, where first production is expected early in 2004 at an anticipated rate of 12 mmcf/d. In the U.K., development plans for the Clapham field include drilling two producing wells and two injectors and tie-in to the Triton production facility. Production from this new field is expected to rise rapidly to an anticipated peak of 15 000 boe/d in 2004.

In North Africa/Near East, our strategy is to exploit the large underdeveloped reserves potential in this region. In Syria, AFPC's near term goal is to sustain gross production at the 300 000 boe/d level for the next few years. For the longer term, we are assessing exploration opportunities. In Libya, we see an opportunity for the future in the application of modern technology to further improve reserves recovery.

In Northern Latin America, our expectations for production growth are currently focused on Trinidad, where Atlantic LNG is building an additional production train to serve the NCMA-1 project. When the train comes on stream in mid-2003, we expect our share of production to grow to 60 mmcf/d. For the longer term, we are looking at emerging exploration opportunities.

Downstream Operating, Marketing and General Costs

Per-litre costs were unchanged from 2001.

■ Unit operating, marketing and general costs *(cents per litre)*

Downstream

Downstream Financial Results

(millions of dollars)	2002	2001	2000
Earnings from operations	$ 254	$ 300	$ 273
Gain (loss) on sale of assets	3	1	(1)
Net earnings	$ 257	$ 301	$ 272
Cash flow	$ 380	$ 589	$ 434
Expenditures on property, plant and equipment	$ 344	$ 383	$ 264
Total assets	$ 3 841	$ 3 556	$ 3 609

2002 COMPARED WITH 2001

Strong operating performance throughout the Downstream in 2002 yielded solid results in a difficult business environment. Total sales of refined products, buoyed by an uplift in retail fuel and asphalt sales, increased to a record 55 700 cubic metres per day (m^3/d) from 54 500 m^3/d in 2001. Despite rising feedstock costs, the earnings contribution from Lubricants operations was up significantly in large part due to a further increase in high-margin sales. Despite the operating performance improvements, Downstream net earnings declined, mainly due to the adverse effects on Refining and Supply of lower refining margins, particularly for distillate, and narrower light/heavy oil price differentials. Downstream operating return on capital employed declined to 10.8 per cent in 2002 from 13.3 per cent in 2001 for the same reasons. Total Downstream operating, marketing and overhead unit costs, at 5.8 cents per litre, were unchanged from 2001. Current income taxes, affecting cash flow, increased to $242 million in 2002 from $90 million in the previous year, mainly due to the net deferral of current taxes, resulting from the inventory accounting method required for income tax purposes. This method resulted in an $85 million increase in current taxes in 2002, compared to a $98 million reduction in 2001.

In the Downstream, profitability improvement initiatives are delivering results.

Downstream Review & Outlook

Strategy

> Generate superior returns by focusing on first-quartile refining performance, advancing Petro-Canada as the brand of choice for Canadian gasoline consumers, and increasing sales of high-margin specialty lubricants.

Operating strategies are focused on strengthening the foundations for improved profitability through effective capital investment and discipline over controllable factors. The target is a minimum 12 per cent return on capital employed, based on a mid-cycle business environment. Petro-Canada's three refineries, strategically located in the major markets of Alberta (Edmonton), Ontario (Oakville) and Quebec (Montreal), account for about 17 per cent of Canada's total refining capacity. The refineries and lubricants plant are already benefiting from restructuring and planning initiatives

implemented over the past two years. A reorganization of the Sales and Marketing group during 2002 has further improved cost structure and is part of the drive towards top quartile Downstream performance.

Executing the strategy

In 2002, our three refineries ran at full capacity, processing a record average 50 400 m^3/d of crude oil, a six per cent increase over 2001 volumes. Improved plant reliability spearheaded the improvement. The overall crude capacity utilization rate was 101 per cent, compared to 96 per cent in 2001. To optimize operations and maintenance procedures, we have implemented Solomon & Associates best practices. As part of efforts to reduce both costs and greenhouse gas emissions, Petro-Canada is committed to reduce energy consumption by an average of at least one per cent per year through 2005.

The capability of the Oakville and Montreal refineries to process heavy oil allows us to lower feedstock costs and gives us a strong position in the asphalt markets in eastern Canada. In 2002, asphalt produced from these heavy crudes totalled a record 1.6 billion litres; however, the financial benefit was moderated by weak industry margins.

In 2002, modifications were completed at the Oakville refinery to reduce sulphur in gasoline to 150 parts per million (ppm) gasoline pool average, as required by the federal government. Construction of desulphurization units for the regulatory requirement of 30 ppm gasoline limit by 2005 has begun at the Edmonton and Montreal refineries. Engineering of the technology solution for sulphur reduction to 30 ppm at Oakville is underway. We expect to meet government timelines in the legislative requirements for low-sulphur gasoline supply.

In Sales and Marketing, the throughput from Petro-Canada's retail network of 1 537 sites averaged 4.1 million litres per site, compared with 3.8 million litres in 2001. The improvement reflects the success of new-image sites, which are achieving annual throughputs averaging in excess of seven million litres. Fast-tracking the re-imaging program has enabled us to capitalize on this compelling market advantage.

Retail site re-imaging and successful sales and marketing programs have generated substantial growth in sales of non-petroleum products and services. Convenience store sales, which were up 30 per cent in 2002 compared with 2001, have grown more than 150 per cent since 1998. In recognition of the quality and success of our convenience store business, Petro-Canada was named 2002 Convenience Store Chain of the Year by leading U.S. trade journal *Convenience Store Decisions*. The award identified outstanding performance in all eight fields of measurement: product quality; customer service; marketing innovation; operating efficiency; management effectiveness; community involvement; image enhancement; and sales and profit performance. This is the first time a non-U.S. retailer has won the award, considered the most prestigious in the North American convenience store industry.

Petro-Canada's growing achievements in retail sales and marketing also include an expanding membership in Petro-Points, Petro-Canada's branded customer loyalty program. At year-end 2002, about 6.6 million Canadian households were Petro-Points members, up 20 per cent from a year earlier. The strong membership growth is being driven by continued program improvements, including points exchange with President's Choice Financial points program and the acceptance of Sears credit cards, which complements the existing points exchange with the Sears points program. The newly launched Petro-Canada Pre-Paid Card, which can be used to purchase any product or service at Petro-Canada locations across the country, is also proving to be a valuable product as well as an additional reward option for Petro-Point members. The Pre-Paid Card is the first of its kind to be offered by a major oil and gas company in Canada.

In the wholesale channel, key strategic initiatives have been implemented, all focused on maintaining our best-in-class position. The Petro-Pass network of 208 truck stop facilities is the leading national marketer of fuel in the commercial road transport segment in Canada. These facilities provide 24-hour access to high speed pumps for faster fueling, as well as a range of enhanced services to meet the needs of the trucking industry. In 2002, we focused on enhancing our leadership position through network expansion and additional wholesale site re-imaging based on the successful retail design. In bulk fuels, new logistics technology was implemented and consolidations were completed to further improve the efficiency of our network.

In Lubricants, our strategy is focused on growing volume in high-margin channels. Petro-Canada enjoys worldwide recognition for its state-of-the-art base oil manufacturing technology, the result of more than 20 years of pioneering work.

Refinery Utilization

Refinery utilization increased reflecting continued reliable operations at the Company's refineries.

- Crude capacity utilization *(per cent)*
- Our rated refinery crude capacity increased in 2001 following process improvements.

Product Sales

Total Downstream sales and sales per retail site continued to grow in 2002.

- Retail throughput per site *(millions of litres per year)*
- Petroleum product sales *(thousands of cubic metres per day)*

The lubricants plant produces the highest quality hydro-treated products as well as low-cost pharmaceutical grade white oils and high viscosity index oils. Products include premium quality lubricants for high-end industrial applications, next-generation engine oils and transmission fluids. In 2002, Lubricants sales totalled 768 million litres, an increase of over three per cent in comparison with sales volume of 744 million litres in 2001, reflecting strong growth in higher value base oils and sales to the automotive sector. In total, high-margin sales rose 10 per cent and now represent over 60 per cent of total Lubricants sales.

Outlook

Plans for improved profitability:

> Maximize refinery plant reliability.
> Increase product value from refinery feedstock slates.
> Secure further reductions in operating costs.
> Continue roll-out of and maximize benefits from retail site re-imaging program.
> Capitalize on the increasing demand for higher quality base oils.

2003 Capital spending plans:

> $360 million for Refining and Supply.
> $125 million for Sales and Marketing.
> $15 million for Lubricants.

The 2003 capital expenditure plans are focused on positioning Petro-Canada for continued profitability, while lessening the environmental impact of our operations and products. The major portion of expenditures in Refining and Supply will focus on refinery reconfigurations to meet new lower limits for sulphur in gasoline. Expenditures in Sales and Marketing will provide for the continued roll-out of Petro-Canada's successful new-image service station program and further development of the Petro-Pass network. At year-end 2002, we were 70 per cent of the way through the retail site re-imaging program, which is focused on converting only those Company-controlled sites that meet economic return criteria. The goal is to complete the program by the end of 2005.

Petro-Canada currently sells over two-thirds of its 350 manufactured lubricants, specialty fluids and greases outside of Canada and the increasing global demand for higher quality base oils offers significant opportunity for long-term growth. As both performance and environmental standards get tougher, the demand for Petro-Canada's finished products and base fluids is expected to continue to grow. By 2005, Lubricants' target is to achieve over 75 per cent of total sales in the higher-margin channel.

Shared Services

Shared Services Financial Results

(millions of dollars)	**2002**	2001	2000
Net expenses from operations [1]	**$ (144)**	$ (51)	$ (98)
Foreign currency translation loss	**(52)**	(96)	(53)
Net expenses [1]	**$ (196)**	$ (147)	$ (151)
Cash flow [1]	**$ (104)**	$ (53)	$ (67)

1 Before reorganization costs in 2000.

2002 COMPARED WITH 2001

Shared Services is structured as a cost centre that includes investment income, interest expense, foreign currency translation and general corporate revenues and expenditures. The rise in net expenses in 2002 reflects a drop in investment and other income and an increase in interest expense, both related to the financing of the Veba acquisition, with a partial offset from a reduction in foreign currency translation loss.

The foreign currency translation loss of $52 million in 2002 includes a $63 million exchange loss from the translation of international subsidiaries. Effective January 1, 2003, Petro-Canada commenced operating Upstream International on a self-sustaining basis. As a consequence, the Company prospectively changed the accounting for the foreign currency translation of its international subsidiaries, whereby future gains or losses arising from the translation of financial statements into Canadian dollars will be deferred and included as part of shareholders' equity.

LIQUIDITY AND CAPITAL RESOURCES

Summary of Cash Flows

(millions of dollars)	**2002**	2001	2000
Net cash inflows (outflows) before changes in non-cash working capital:			
Cash flow	**$ 2 276**	$ 1 688	$ 1 870
Investing activities	**(4 141)**	(1 564)	(489)
Financing activities	**1 560**	(909)	(214)
	(305)	(785)	1 167
(Increase) decrease in non-cash working capital and other	**(242)**	151	42
(Decrease) increase in cash and short-term investments	**$ (547)**	$ (634)	$ 1 209
Cash and short-term investments at year-end	**$ 234**	$ 781	$ 1 415

Operating Activities

The reduction in net cash outflow before changes in non-cash working capital primarily reflects the impact of the Veba acquisition, with offsets from the related financing arrangements and increased cash flow from operations.

The increase of $242 million in non-cash operating working capital, excluding working capital relating to acquisitions, was mainly due to an increase in accounts receivable and a decrease in income taxes payable, partially offset by an increase in accounts payable and accrued liabilities. The higher levels of accounts receivable and payable reflect the significantly higher prices for both oil and natural gas at 2002 year-end compared with 2001 year-end. The decrease in cash and short-term investments reflects the use of funds towards financing the Veba acquisition, as well as to repay $461 million of the related credit facilities.

Investing Activities

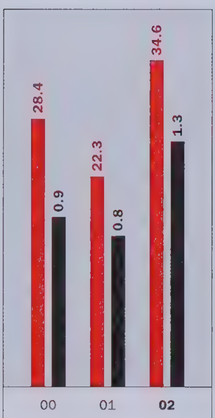
Capital and Exploration Expenditures

(millions of dollars)	**2002**	2001	2000
Acquisition of oil and gas operations of Veba Oil & Gas GmbH	**$ 2 234**	$ –	$ –
Upstream Canada [1]			
North American Natural Gas	**529**	554	434
East Coast Oil	**290**	273	340
Oil Sands	**462**	304	110
	1 281	1 131	884
Upstream International [1]			
Northwest Europe	**93**	–	23
North Africa/Near East	**108**	153	20
Northern Latin America	**20**	–	–
	221	153	43
Downstream			
Refining and supply	**210**	206	102
Sales and marketing	**118**	156	143
Lubricants	**16**	21	19
	344	383	264
Shared Services	**15**	14	12
Total property, plant and equipment and exploration	**1 861**	1 681	1 203
Deferred charges and other assets	**72**	10	8
Total	**$ 4 167**	$ 1 691	$ 1 211

1 Includes exploration expenses charged to earnings, totalling $301 million in 2002, $245 million in 2001 and $171 million in 2000.

Key Debt Ratios

Despite debt taken on to finance the International acquisition, we are well positioned relative to our target levels.



■ Debt to debt plus equity *(per cent)*

■ Debt to cash flow *(times)*

We retired $461 million by year-end 2002 and an additional $100 million in January 2003 of the $2.1 billion debt we assumed to finance the International acquisition.

2002 COMPARED WITH 2001

The substantial capital spending in the Upstream reflects Petro-Canada's continuing commitment to long-term profitable growth. Investments in Upstream Canada included $399 million for exploration and development of natural gas in Western Canada and $110 million for other natural gas opportunities in North America, principally in the Mackenzie Delta and offshore Nova Scotia. Major funding for exploration and development of crude oil offshore Canada's East Coast included $82 million to complete development of Terra Nova and $132 million towards development of White Rose, mostly related to the fabrication of a new FPSO vessel. Oil sands investments included $222 million for Syncrude, mainly for the Stage 3 expansion; $114 million to complete development of the MacKay River oil sands *in situ* project; $97 million for the Edmonton refinery conversion and $29 million for other oil sands work, principally drilling activity at Meadow Creek, Petro-Canada's planned second *in situ* development project.

Expenditures in Upstream International were incurred, for the most part, over the last eight months of the year following the Veba acquisition, and largely related to ongoing programs in the U.K. North Sea, Syria, Libya, Kazakhstan and Trinidad. Major investments in the Downstream focused on the fast-track development of our new-image retail sites and programs to comply with sulphur-in-gasoline regulations.

Petro-Canada's capital expenditure budget for 2003 is $2 575 million, up 38 per cent from the $1 861 million of expenditures on property, plant and equipment and exploration in 2002, reaffirming our commitment to profitable growth and the creation of long-term shareholder value. About $1 500 million of 2003 budgeted expenditures are allocated to activities in Upstream Canada, $545 million to Upstream International, $500 million to the Downstream, and $30 million for corporate and other purposes. We plan to fund the 2003 capital expenditure program from cash flow.

Financing Activities and Dividends

Sources of Capital Employed

(millions of dollars)	**2002**	2001	2000
Long-term debt, including current portion	**$ 3 057**	$ 1 401	$ 1 774
Shareholders' equity	**5 776**	4 877	4 465
Total	**$ 8 833**	$ 6 278	$ 6 239

On May 2, 2002, Petro-Canada acquired the majority of the international oil and gas businesses of Veba Oil & Gas GmbH and, on December 10, 2002, Petro-Canada acquired from Veba a 50 per cent working interest in the La Ceiba block in Venezuela which had been subject to rights of first refusal. The total acquisition cost, consisting of a cash consideration and acquisition costs, was $2 234 million. This is considerably lower than the previously announced $3 200 million, due to the exercise of rights of first refusal affecting a number of properties included in the original acquisition proposal and the unresolved right of first refusal related to assets in Venezuela. Funds for the acquisition were provided from new credit facilities arranged with certain banks (See Note 16 of Notes to Consolidated Financial Statements) and from cash and short-term investments. The net increase in debt at 2002 year-end reflects the drawdown of $2 100 million of the acquisition credit facility, less total debt repayments of $465 million during the year, and a new capital lease of $32 million. An additional $100 million of the acquisition credit facility was repaid in January 2003. Petro-Canada plans to meet remaining repayment commitments out of a combination of cash flow and by accessing debt capital markets.

For operating purposes, Petro-Canada has access to a portion of the new credit facilities and other undrawn bank lines of credit for a total of $1 427 million. As of December 31, 2002, Petro-Canada had cash and short-term investments of $234 million and no commercial paper outstanding. Petro-Canada will continue to use its cash position, and the issuance of short-term debt if necessary, to meet working capital and other financing requirements.

While the debt taken on to finance the acquisition significantly increased our financial leverage, we expect debt to cash flow, our key leverage measure, to remain within our target range of no more than two times. At December 31, 2002, this ratio stood at 1.3 times, up from 0.8 times at the end of 2001. Debt to debt plus equity, our long-

term measure for capital structure, rose to 34.6 per cent at 2002 year-end compared with 22.3 per cent at the prior year-end, but we expect to reduce this, over time, to our target level of 30 per cent.

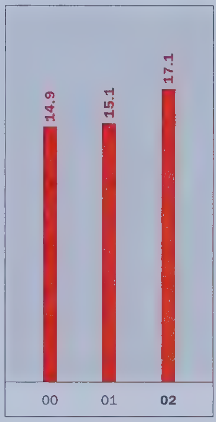
Petro-Canada does not engage in off-balance sheet accounting to structure any of its financial arrangements. Off-balance sheet activities are limited to matters such as guarantees, none of which would have a material impact on the Company's financial results, liquidity or capital resources.

At 2002 year-end, Petro-Canada's defined benefits pension plans were under-funded for accounting purposes by $279 million, up from $80 million at the end of 2001, mainly reflecting the impact of weak capital markets on fund assets. As a consequence of the increased deficit, Petro-Canada will make a cash contribution of about $30 million to the fund during 2003 and we expect the pension expense to increase by approximately $45 million before tax. On a per share basis, the after-tax expense increase represents about $0.10 per share for the year.

Petro-Canada reviews its dividend strategy from time to time to ensure the alignment of dividend policy with shareholder expectations and our financial and growth objectives. In 2002, Petro-Canada paid $105 million in dividends, compared with $106 million in 2001. The current quarterly dividend is $0.10 per share.

Interest Coverage

A positive interest coverage ratio demonstrates more than sufficient earnings to cover interest charges on debt.



■ Interest coverage ratio *(times)*

– Calculated on an EBITDAX basis.

Financial Ratios

	2002	2001	2000
Interest coverage *(times)*:			
earnings basis	**10.5**	9.7	10.0
EBITDAX basis	**17.1**	15.1	14.9
cash flow basis	**17.9**	15.6	15.2
Debt to cash flow *(times)*	**1.3**	0.8	0.9
Debt to debt plus equity *(per cent)*	**34.6**	22.3	28.4

RISK MANAGEMENT

Petro-Canada's risk management activities are conducted according to policies and guidelines established by the Board of Directors, using insurance, selective hedging and other techniques. Our risk management policy prohibits the use of derivative instruments for speculative purposes. Petro-Canada uses derivatives primarily to hedge physical transactions for operational needs and to facilitate sales to customers. Commodity prices and margins may be hedged occasionally to capture opportunities that represent extraordinary value. Except as specifically authorized by the Board, the term of hedging instruments cannot exceed 18 months. We transact derivatives with counterparties who possess a minimum long-term credit rating of A (unless otherwise approved by the Board) under a signed International Swap Dealers Association agreement. Credit limits take into account current and potential exposure to losses due to non-performance of a counterparty and reduce credit risk concentration with any single counterparty. Monitoring and reporting of the derivatives portfolio includes periodic testing of the fair value of all outstanding derivatives. Commodity, currency and interest rate hedges resulted in a net decrease in earnings of about $22 million after tax in 2002, compared with a net increase in earnings of about $10 million in 2001.

As at December 31, 2002, crude oil, natural gas and foreign exchange contracts had been bought forward to mitigate exposure on fixed-price natural gas and refined product sales. Short-term hedge positions were also in place for refining supply and product purchases. Short duration Forward Rate Agreements have been implemented to manage the interest rate exposure on floating debt and, in anticipation of accessing debt capital markets in 2003, Petro-Canada has entered into interest rate derivatives to hedge a portion of its exposure to adverse interest rate fluctuations.

Petro-Canada has future commitments to sell and transport natural gas associated with normal operations. About four per cent of our estimated 2003 Upstream Canada natural gas production is sold under future fixed-price commitments at an average plant gate netback price of $2.73 per mcf. Sales under these contracts will drop by about 40 per cent in 2004 compared to the 2003 level of sales.

Petro-Canada manages operational risk through comprehensive risk assessment and loss

management processes, and maintains adequate insurance coverage. We place insurance coverage globally, with financially secure insurers. Limits of insurance are based on engineering risk assessments and deductibles are set at levels that reflect our ability to retain the risk.

We also employ high levels of technical expertise and leading-edge technology to mitigate exploratory risks. To secure strategic and competitive advantages, Petro-Canada has entered into a variety of alliances with world-class suppliers of industry goods and services. These alliances provide preferential access, reliability, advanced technology, high quality and competitive prices, mitigating variability in costs associated with exploration and development as industry conditions fluctuate.

CORPORATE RESPONSIBILITY

At Petro-Canada, we take pride in being a good corporate citizen. Strong environment, health and safety performance is fundamental to our business as an energy company.

While Petro-Canada is in business to provide a competitive return to shareholders, we recognize that economic performance is not the only criterion on which our company is evaluated.

To review our performance in environmental stewardship, health and safety and community involvement in more detail than can be accommodated in the Annual Report, we publish an annual Report to the Community. The report gathers data on key non-financial performance measures, enabling the public to assess our ongoing efforts in these areas. The Report to the Community can be viewed on our Web site at www.petro-canada.ca, or obtained from Corporate Communications. The 2002 Report to the Community will be available in July 2003.

Corporate Governance

Petro-Canada strives to attain the highest standards of corporate governance. The company has evolved its management and internal reporting systems to provide a high level of assurance that corporate responsibility is part of our day-to-day business decision-making process. These governance systems begin with the Board of Directors and extend throughout the company.

Petro-Canada has a range of tools to establish and enforce appropriate conduct for all employees, including a Code of Business Conduct and Principles for Investment and Operations. Both of these documents can be viewed on our Web site at www.petro-canada.ca.

The Company's Management Proxy Circular, which is mailed to shareholders and is also available for viewing online, includes a Statement of Corporate Governance Practices, reference to the Corporate Governance Handbook, mandates and reports of Board committees, and detail on Directors' business background, tenure, committee membership, remuneration and share ownership. The Board of Directors has responsibility for ensuring timely and appropriate information disclosure to security holders and regulators. We believe the Corporation is well aligned with the guidelines adopted by the Toronto Stock Exchange and the recently proposed disclosure requirements under the Sarbanes-Oxley Act of 2002. For detailed information, please refer to Appendix A in the Management Proxy Circular.

The Corporate Governance and Nominating Committee, composed entirely of unrelated directors, oversees the Corporation's corporate governance process and is responsible for addressing governance issues and proposing to the Board candidates for election to the Board of Directors. The committee and management undertook an extensive review following proclamation of the Sarbanes-Oxley Act of 2002, and recommended areas of improvement in the Corporation's current practices as well as highlighted achievements.

Environment, Health and Safety

Petro-Canada executives are responsible for developing operational procedures and standards in compliance with our environment, health and safety policies and Total Loss Management standards under which we conduct a major review of each business unit every four years. Our Executive Leadership Team reviews environment, health and safety performance monthly. As well, critical issues and EHS performance are reviewed by the Environment, Health and Safety Committee of the Board of Directors three times per year.

In 2002, we invested \$318 million in environmental programs, including \$90 million for operating expenses and \$228 million in capital expenditures for facility upgrades. Some of the expenditures include site remediation, environmental assessments, and pollution prevention and control equipment. We expect environmental

costs to remain high, as we prepare to meet new federal limits for sulphur in gasoline, future fuel reformulation requirements, and tighter environmental standards for oil and gas production. The cost impact of the federal government's ratification of the Kyoto Protocol on greenhouse gas emissions, particularly on large, capital-intensive projects, has yet to be determined.

Climate change is one of the most complex issues facing Canadian industry, the Canadian public, and governments today. At Petro-Canada, we support a balanced and responsible approach that promotes action on the issue of climate change.

Petro-Canada has renewed its commitment to improve energy efficiency in each business sector by an average of one per cent per year from 2000 to 2005. Key components of these improvements include reductions in fuel consumption and the corresponding lowering of greenhouse gas emissions.

Since 1990, Petro-Canada has improved energy efficiency in the Downstream by 15 per cent and in the Upstream by 52 per cent. By implementing energy efficiency and emissions reduction projects, we have reduced ongoing annual greenhouse gas emissions by approximately 1.2 million tonnes of CO_2 equivalent, while increasing overall production by 23 per cent. Data for 2002 will be provided in this year's Report to the Community.

The safety and well-being of our employees is a high priority for Petro-Canada. Occupational health and safety programs are designed to contribute to employee well-being and provide a safe and healthy work environment. Our overall Employee Recordable Injury Frequency (per 200 000 person hours) decreased to 0.94 in 2002 from 1.14 in 2001. Recordable injuries decreased to 44 in 2002 from 46 in 2001. Over the past year, Petro-Canada has renewed efforts to introduce further initiatives focused on injury reduction.

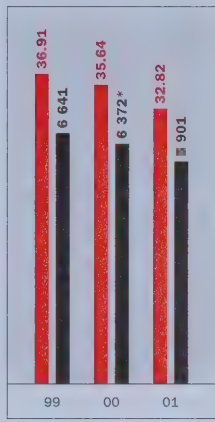
Community Involvement

Petro-Canada's success depends on the support of Canadians, so we actively invest and participate in the communities where we work and live across the country.

In 2002, Petro-Canada invested $5 million in 375 Canadian non-profit organizations in four sectors – education, the environment, health and community services, and arts and culture. We also contributed another $800 000 from our Olympic Torch Scholarship Fund, and approximately $300 000 in in-kind contributions. Through our Volunteer Energy Program, we provided 403 grants of $500 each to non-profit organizations supported by employees and retirees who give their time to the community.

Greenhouse Gas Emissions versus Production

Petro-Canada is committed to reducing GHG emissions in our Upstream and Downstream operations, primarily by improving energy efficiency.



■ Total Upstream and Downstream production *(million cubic metres of oil equivalent/year)*

■ GHG emissions *(kilotonnes/year)*

* Year 2000 data has been restated and is slightly higher than was reported in last year's report.

– 2002 data is not yet available; data is based on reporting 100 per cent from Petro-Canada operated properties.

World Business Council for Sustainable Development

THE GLOBAL COMPACT

Imagine A Caring Company

™ Official Mark of the Canadian Olympic Association

vcr-mvr inc. Gold™ Champion Level Reporter

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The preparation and presentation of the Company's consolidated financial statements and the overall quality of the Company's financial reporting are the responsibility of management. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include estimates that are based on management's best judgements. Information contained elsewhere in the Annual Report is consistent, where applicable, with that contained in the financial statements.

Management is also responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of financial statements.

Arthur Andersen LLP, a firm of chartered accountants, was appointed by the shareholders as external auditors of the Company in April 2002 and resigned as external auditors in June 2002, when substantially all of the partners and staff of Arthur Andersen LLP in Canada joined Deloitte & Touche LLP. In June 2002 the Board of Directors appointed Deloitte & Touche LLP as external auditors, until the next annual meeting of shareholders, to conduct an independent examination and express their opinion on the consolidated financial statements. The Auditors' Report outlines the auditors' opinion and the scope of their examination. The services provided to the Company by the external auditors are now restricted to the audit of the consolidated financial statements and audit-related services. The Company had engaged Arthur Andersen LLP and subsequently Deloitte & Touche LLP, who were replaced by PricewaterhouseCoopers LLP in August 2002 as the contract auditor to provide internal audit services, including a review of the system of internal controls to ensure that there are no significant weaknesses.

The Board of Directors is responsible for overseeing management's performance of its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit, Finance and Risk Committee of the Board.

R.A. Brenneman

Ronald A. Brenneman
Chief Executive Officer

E.F.H. Roberts

Ernest F.H. Roberts
Senior Vice-President and Chief Financial Officer

January 29, 2003

AUDIT, FINANCE AND RISK COMMITTEE OF THE BOARD OF DIRECTORS

The Audit, Finance and Risk Committee, which is composed of not less than three (currently five) directors who are not employees of the Company, assists the Board of Directors in the discharge of its responsibility for overseeing management's performance of the financial reporting and internal control responsibilities. The Committee reviews the annual and quarterly consolidated financial statements, accounting policies and the overall quality of the Company's financial reporting, and the financial information contained in prospectuses and in reports filed with regulatory authorities, as required. The Committee also reviews and makes recommendations to the Board regarding financial matters and oversees the process that management has in place to identify business risks.

With respect to the external auditors, the Committee reviews and approves the terms of engagement, the scope and plan for the external audit and reviews the results of the audit and the Auditors' Report. The Committee discusses the external auditors' independence from management and the Company with the auditors and receives written confirmation of their independence. The Committee also recommends to the Board the external auditors to be appointed by the shareholders and approves their fees.

With respect to the contract auditor's engagement to provide internal audit services, the Committee reviews the engagement contract, reviews and approves the scope and plan for the internal audit, receives periodic reports and reviews significant findings and recommendations.

Senior management, the external auditors and the contract auditor attend all Audit, Finance and Risk Committee meetings and each is provided with the opportunity to meet privately with the Committee.

Claude Fontaine

Claude Fontaine
Chairman of the Audit, Finance and Risk Committee

January 29, 2003

AUDITORS' REPORTS

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 2002 and the consolidated statements of earnings, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements of Petro-Canada as at December 31, 2001 and for each of the years in the two-year period ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those consolidated financial statements in their report dated January 31, 2002. As described in Note 2, these consolidated financial statements have been restated to give effect to the accounting policy change relating to foreign exchange. We audited the adjustments described in Note 2 that were applied to restate the 2001 and 2000 consolidated financial statements. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 and 2000 consolidated financial statements of the Company other than with respect to such adjustments and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 financial statements taken as a whole.

Deloitte & Touche LLP

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta

January 29, 2003

To the Shareholders of Petro-Canada:

We have audited the consolidated balance sheet of Petro-Canada as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Arthur Andersen LLP

Arthur Andersen LLP
Chartered Accountants
Calgary, Alberta

January 31, 2002

CONSOLIDATED STATEMENT OF EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,	2002	2001	2000
REVENUE			
Operating	**$ 9 917**	$ 8 582	$ 9 372
Investment and other income *(Note 5)*	**–**	154	173
	9 917	8 736	9 545
EXPENSES			
Crude oil and product purchases	**4 556**	4 687	5 537
Operating, marketing and general *(Note 6)*	**2 036**	1 670	1 619
Exploration	**301**	245	171
Depreciation, depletion and amortization	**957**	568	584
Foreign currency translation *(Note 7)*	**52**	102	67
Interest	**187**	135	144
	8 089	7 407	8 122
EARNINGS BEFORE INCOME TAXES	**1 828**	1 329	1 423
PROVISION FOR INCOME TAXES *(Note 8)*			
Current	**959**	528	363
Future	**(105)**	(45)	201
	854	483	564
NET EARNINGS	**$ 974**	$ 846	$ 859
EARNINGS PER SHARE *(dollars) (Note 9)*			
Basic	**$ 3.71**	$ 3.19	$ 3.15
Diluted	**$ 3.67**	$ 3.16	$ 3.13

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(stated in millions of Canadian dollars)

For the years ended December 31,	2002	2001	2000
RETAINED EARNINGS AT BEGINNING OF YEAR, as previously reported	**$ 1 695**	$ 897	$ 113
Retroactive application of change in accounting policy *(Note 2)*	**(184)**	(126)	(92)
RETAINED EARNINGS AT BEGINNING OF YEAR, as restated	**1 511**	771	21
Net earnings	**974**	846	859
Dividends on common shares	**(105)**	(106)	(109)
RETAINED EARNINGS AT END OF YEAR	**$ 2 380**	$ 1 511	$ 771

CONSOLIDATED STATEMENT OF CASH FLOWS

(stated in millions of Canadian dollars)

For the years ended December 31,	**2002**	2001	2000
OPERATING ACTIVITIES			
Net earnings	**$ 974**	$ 846	$ 859
Items not affecting cash flow *(Note 10)*	**1 001**	597	840
Exploration expenses *(Note 14)*	**301**	245	171
Cash flow	**2 276**	1 688	1 870
(Increase) decrease in non-cash working capital related to operating activities and other *(Note 11)*	**(226)**	55	87
Cash flow from operating activities	**2 050**	1 743	1 957
INVESTING ACTIVITIES			
Acquisition of oil and gas operations of Veba Oil & Gas GmbH *(Note 3)*	**(2 234)**	–	–
Expenditures on property, plant and equipment and exploration *(Note 14)*	**(1 861)**	(1 681)	(1 203)
Proceeds from sales of assets	**26**	127	722
Increase in deferred charges and other assets, net	**(72)**	(10)	(8)
(Increase) decrease in non-cash working capital related to investing activities *(Note 11)*	**(16)**	96	(44)
	(4 157)	(1 468)	(533)
FINANCING ACTIVITIES			
Proceeds from issue of long-term debt	**2 100**	–	–
Reduction of long-term debt	**(465)**	(475)	(4)
Proceeds from issue of common shares	**30**	34	33
Dividends on common shares	**(105)**	(106)	(109)
Purchase of common shares *(Note 18)*	**–**	(362)	(134)
Increase in non-cash working capital related to financing activities *(Note 11)*	**–**	–	(1)
	1 560	(909)	(215)
(DECREASE) INCREASE IN CASH AND SHORT-TERM INVESTMENTS	**(547)**	(634)	1 209
CASH AND SHORT-TERM INVESTMENTS AT BEGINNING OF YEAR	**781**	1 415	206
CASH AND SHORT-TERM INVESTMENTS AT END OF YEAR	**$ 234**	$ 781	$ 1 415

CONSOLIDATED BALANCE SHEET

(stated in millions of Canadian dollars)

As at December 31,	**2002**	2001
ASSETS		
CURRENT ASSETS		
Cash and short-term investments *(Note 12)*	**$ 234**	$ 781
Accounts receivable	**1 596**	758
Inventories *(Note 13)*	**585**	455
Prepaid expenses	**19**	15
	2 434	2 009
PROPERTY, PLANT AND EQUIPMENT, NET *(Note 14)*	**10 084**	7 460
GOODWILL *(Note 3)*	**709**	–
DEFERRED CHARGES AND OTHER ASSETS *(Note 15)*	**212**	165
	$ 13 439	$ 9 634
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**$ 1 901**	$ 1 158
Income taxes payable	**263**	234
Current portion of long-term debt *(Note 16)*	**356**	5
	2 520	1 397
LONG-TERM DEBT *(Note 16)*	**2 701**	1 396
DEFERRED CREDITS AND OTHER LIABILITIES *(Note 17)*	**621**	481
FUTURE INCOME TAXES *(Note 8)*	**1 821**	1 483
COMMITMENTS AND CONTINGENT LIABILITIES *(Note 22)*		
SHAREHOLDERS' EQUITY *(Note 18)*	**5 776**	4 877
	$ 13 439	$ 9 634

Approved on behalf of the Board

Ron Brenneman
Director

Brian MacNeill
Director

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts stated in millions of Canadian dollars)

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of Presentation The consolidated financial statements include the accounts of Petro-Canada and of all subsidiary companies ("the Company") and comply with Canadian generally accepted accounting principles ("GAAP"). Differences between Canadian and United States GAAP are explained in the Notes to the Consolidated Financial Statements.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Only the Company's proportionate interest in such activities is reflected in the financial statements.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

(b) Revenue Recognition Revenue from the sale of crude oil, natural gas, natural gas liquids, purchased products, and refined petroleum products are recorded when title passes to the customer.

International operations conducted pursuant to exploration and production sharing agreements ("EPSA's") are reflected in the Consolidated Financial Statements based on the Company's working interest in such operations. Under the EPSA's, the Company and other non-governmental partners pay all operating and capital costs for exploring and developing the concessions. Each EPSA establishes specific terms for the Company to recover these costs ("Cost Recovery Oil") in accordance with a formula that is generally limited to a specified percentage of production during each fiscal year and to share in the production profits ("Profit Oil"). Profit Oil is that portion of production remaining after deducting Cost Recovery Oil and is shared between the joint venture partners and the government of each country, varying with the level of production. Profit Oil that is attributable to the government includes an amount in respect of all deemed income taxes payable by the Company under the laws of the respective country. All other government stakes, other than income taxes, are considered to be royalty interests.

(c) Foreign Currency Translation Monetary assets and liabilities are translated into Canadian dollars at rates of exchange in effect at the balance sheet date. Other assets and related depreciation, depletion and amortization, other liabilities, revenue and other expense items are translated at rates of exchange in effect at the respective transaction dates. The resulting exchange gains or losses are included in earnings.

Foreign operations are integrated with the Company's other activities and are translated in the manner described above.

(d) Income Taxes The Company follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized, using substantively enacted income tax rates, based on the differences between the carrying amounts of assets and liabilities reported in the financial statements and their respective tax bases. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in income in the period the change occurs.

(e) Earnings Per Share Basic earnings per share is calculated by dividing the net earnings available to common shareholders by the weighted average number of common shares outstanding. Diluted earnings per share reflects the potential dilution that would occur if stock options were exercised. The treasury stock method is used in calculating diluted earnings per share, which assumes that any proceeds received from the exercise of in-the-money stock options would be used to purchase common shares at the average market price for the period.

(f) Cash and Short-Term Investments Cash and short-term investments comprise cash in banks, less outstanding cheques, and deposits with a maturity of less than 90 days when purchased.

(g) Inventories Inventories are stated at the lower of cost and net realizable value. Cost of crude oil and products is determined primarily on a "last-in, first-out" ("LIFO") basis.

(h) Investments Investments in companies over which the Company has significant influence are accounted for on the equity method. Other long-term investments are accounted for on the cost method.

Note 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *continued*

(i) Property, Plant and Equipment Investments in exploration and development activities are accounted for on the successful efforts method. Under this method the acquisition cost of unproved acreage is capitalized. Costs of exploratory wells are initially capitalized pending determination of proved reserves and costs of wells that are assigned proved reserves remain capitalized while costs of unsuccessful wells are charged to earnings. All other exploration costs, including geological and geophysical costs, are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

The interest cost of debt attributable to the construction of major new facilities is capitalized during the construction period.

Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset.

(j) Depreciation, Depletion and Amortization Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method.

Depreciation of other plant and equipment is provided on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate.

Costs associated with significant development projects are not depleted until commencement of commercial production.

(k) Future Removal and Site Restoration Costs Estimated future removal and site restoration costs which are probable and can be reasonably determined are provided for on either the unit of production method or the straight line method, based on the estimated service lives of the related assets, as appropriate. Future removal and site restoration costs for inactive Downstream sites, net of expected recoveries, are provided for at the time a decision is made to decommission the site. The annual provision is included in operating, marketing and general expenses and is estimated based on current costs and technology and in accordance with existing legislation and industry practice.

(l) Goodwill Goodwill is the excess purchase price over the fair value of identifiable assets and liabilities acquired. Goodwill impairment is assessed annually, or as economic events dictate, by comparing the fair value of the reporting unit to its carrying value, including goodwill. If the fair value of the reporting unit is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the fair value of the goodwill.

(m) Stock Option Plan The Company maintains a stock option plan for directors, officers and certain employees as described in the Notes to the Consolidated Financial Statements. The stock options are accounted for based on the intrinsic value of the award at grant date. Consideration paid on exercise of stock options is credited to common shares.

(n) Employee Future Benefits The Company records its obligations under employee benefit plans, net of plan assets where applicable. The costs of pensions and other post-retirement benefits are actuarially determined using the projected benefit method prorated based on service and using management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, and expected health care costs. For the purpose of calculating the expected return on plan assets, those assets are measured at fair value. The accrued benefit obligation is discounted using a market rate of interest at the beginning of the year on high quality corporate debt instruments.

(o) Hedging and Derivative Financial Instruments The Company may use derivative financial instruments to manage its exposure to market risks resulting from fluctuations in foreign exchange rates, interest rates, and commodity prices. These derivative financial instruments are not used for trading or speculative purposes.

Gains and losses on derivative instruments that are designated as and determined to be effective hedges are deferred and recognized in the period of settlement as a component of the related transaction. If a derivative instrument ceases to be effective, hedge accounting is terminated and future gains or losses are recognized in the statement of earnings in the current period. Derivative instruments that are not hedges for accounting purposes are recorded at fair value with any resulting gain or loss recognized in the statement of earnings in the current period.

Note 2 CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2002 the Company adopted, retroactively, the recommendations of the Canadian Institute of Chartered Accountants on accounting for foreign currency translation whereby an exchange gain or loss on the translation of long-term debt is included in net earnings in the current period. Previously, the gain or loss on the translation of long-term debt was deferred and amortized over the remaining term of the debt. The effect of this change for the year ended December 31, 2002 was an increase (decrease) in net earnings of $19 million (2001 – $(58) million; 2000 – $(34) million) from the net earnings that would have been reported under the former accounting policy. The change also resulted in a decrease in deferred charges and other assets of $187 million, a decrease in future income taxes of $3 million, and a decrease in shareholders' equity of $184 million as of December 31, 2001.

Effective January 1, 2002 the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for stock-based compensation and other stock-based payments. The Company has elected to continue accounting for stock-based compensation based on the intrinsic value at the date of granting and to disclose the pro forma results of using the fair value based method. Accordingly, the net earnings for the reported periods remain unchanged and the pro forma results are disclosed in Note 18. The new recommendations have been applied to options granted after January 1, 2002.

Note 3 ACQUISITION OF OIL AND GAS OPERATIONS OF VEBA OIL & GAS GMBH

On May 2, 2002 the Company acquired the shares of companies holding the majority of the international oil and gas operations of Veba Oil & Gas GmbH and on December 10, 2002 the Company acquired certain of the remaining operations which were subject to rights of first refusal. The total acquisition cost, consisting of cash consideration and acquisition costs, was $2 234 million and the results of these operations have been included in the consolidated financial statements from the dates of acquisition. The remaining operations not yet acquired are in Venezuela and are subject to rights of first refusal.

The acquisition was accounted for by the purchase method of accounting and the estimated allocation of fair value to the assets acquired and liabilities assumed was:

Property, plant and equipment	$ 2 012
Goodwill	709
Current assets, excluding cash of $15 million	640
Deferred charges and other assets	6
Total assets acquired	3 367
Current liabilities	634
Future income taxes	387
Deferred credits and other liabilities	112
Total liabilities assumed	1 133
Net assets acquired	$ 2 234

Although the estimated allocation of fair value to the assets acquired and liabilities assumed is subject to changes as additional information becomes available, the final allocation is not expected to differ materially from the estimated allocation.

Goodwill, which is not tax deductible, was assigned to the Company's International business segment.

Funds for the acquisition were provided from credit facilities arranged with certain banks (Note 16) and from cash and short-term investments.

Note 4 SEGMENTED INFORMATION

The Company's upstream and downstream activities are conducted through three business segments.

Upstream operations include the exploration, development, production, transportation and marketing activities for crude oil, natural gas liquids, and oil sands. Activities are conducted through the Upstream Canada and Upstream International business segments. The Upstream Canada segment includes activity in the Western Canada, East Coast Offshore, Mackenzie Delta and Alaska regions. The Upstream International segment includes activity in the United Kingdom, the Netherlands, Trinidad, Venezuela, Syria, Libya, Kazakhstan, Algeria and Tunisia.

	UPSTREAM					
	CANADA			INTERNATIONAL		
	2002	2001	2000	**2002**	2001	2000
Revenue						
Sales to customers and other revenues	**$ 1 354**	$ 1 490	$ 1 659	**$ 1 239**	$ 20	$ 59
Inter-segment sales	**968**	642	619	**–**	–	–
Segment Revenue	**2 322**	2 132	2 278	**1 239**	20	59
Expenses						
Crude oil and product purchases	**–**	–	92	**–**	–	–
Inter-segment transactions	**3**	6	6	**–**	–	–
Operating, marketing and general	**509**	458	395	**288**	8	25
Exploration	**246**	194	124	**55**	51	47
Depreciation, depletion and amortization	**507**	367	357	**249**	7	27
Foreign currency translation	**–**	–	–	**–**	–	–
Interest	**–**	–	–	**–**	–	–
	1 265	1 025	974	**592**	66	99
Earnings before income taxes	**1 057**	1 107	1 304	**647**	(46)	(40)
Provision for income taxes						
Current	**414**	502	175	**413**	(15)	61
Future	**(45)**	(114)	331	**9**	(4)	(79)
	369	388	506	**422**	(19)	(18)
Reorganization costs *(Note 6)*	**–**	–	–	**–**	–	–
Net earnings	**$ 688**	$ 719	$ 798	**$ 225**	$ (27)	$ (22)
Capital and Exploration Expenditures						
Acquisition of oil and gas operations of Veba Oil & Gas GmbH, including goodwill	**$ –**	$ –	$ –	**$ 2 234**	$ –	$ –
Property, plant and equipment and exploration expenditures	**1 281**	1 131	884	**221**	153	43
Deferred charges and other assets	**(3)**	–	4	**–**	(6)	–
	$ 1 278	$ 1 131	$ 888	**$ 2 455**	$ 147	$ 43
Cash Flow (before changes in non-cash working capital)	**$ 1 417**	$ 1 125	$ 1 460	**$ 583**	$ 27	$ 78
Total Assets	**$ 5 922**	$ 5 118	$ 4 811	**$ 3 544**	$ 186	$ 148

Note 4 **SEGMENTED INFORMATION** *continued*

The Downstream segment includes the purchase and sale of crude oil, the refining of crude oil products and the distribution and marketing of these and other purchased products.

All activities, other than those relating to the Upstream International segment and Alaska, are conducted within Canada.

Financial information by business segment is presented in the following table as though each segment were a separate business entity. Inter-segment transfers of products, which are accounted for at market value, are eliminated on consolidation. Shared Services includes investment income, interest expense, foreign currency translation and general corporate revenue and expense. Shared Services assets are principally cash and short-term investments and other general corporate assets.

DOWNSTREAM			SHARED SERVICES			CONSOLIDATED		
2002	2001	2000	**2002**	2001	2000	**2002**	2001	2000
$ 7 318	$ 7 158	$ 7 782	**$ 6**	$ 68	$ 45	**$ 9 917**	$ 8 736	$ 9 545
3	6	6	**–**	–	–			
7 321	7 164	7 788	**6**	68	45	**9 917**	8 736	9 545
4 556	4 687	5 446	**–**	–	(1)	**4 556**	4 687	5 537
968	642	619	**–**	–	–			
1 179	1 165	1 079	**60**	39	54	**2 036**	1 670	1 553
–	–	–	**–**	–	–	**301**	245	171
200	193	187	**1**	1	13	**957**	568	584
–	–	–	**52**	102	67	**52**	102	67
–	–	–	**187**	135	144	**187**	135	144
6 903	6 687	7 331	**300**	277	277	**8 089**	7 407	8 056
418	477	457	**(294)**	(209)	(232)	**1 828**	1 329	1 489
242	90	231	**(110)**	(49)	(81)	**959**	528	386
(81)	86	(46)	**12**	(13)	–	**(105)**	(45)	206
161	176	185	**(98)**	(62)	(81)	**854**	483	592
–	–	–	**–**	–	–	**–**	–	38
$ 257	$ 301	$ 272	**$ (196)**	$ (147)	$ (151)	**$ 974**	$ 846	$ 859
$ –	$ –	$ –	**$ –**	$ –	$ –	**$ 2 234**	$ –	$ –
344	383	264	**15**	14	12	**1 861**	1 681	1 203
27	16	7	**48**	–	(3)	**72**	10	8
$ 371	$ 399	$ 271	**$ 63**	$ 14	$ 9	**$ 4 167**	$ 1 691	$ 1 211
$ 380	$ 589	$ 434	**$ (104)**	$ (53)	$ (102)	**$ 2 276**	$ 1 688	$ 1 870
$ 3 841	$ 3 556	$ 3 609	**$ 132**	$ 774	$ 1 432	**$ 13 439**	$ 9 634	$ 10 000

Note 5 (LOSSES) GAINS ON DISPOSAL OF ASSETS

Investment and other income includes net (losses) gains on disposal of non-core assets of $(2) million (2001 – $49 million; 2000 – $73 million).

Note 6 OPERATING, MARKETING AND GENERAL EXPENSES

Operating, marketing and general expenses in 2000 includes a provision of $66 million for staff reductions and related building expenses. The provision decreased 2000 net earnings by $38 million.

Note 7 FOREIGN CURRENCY TRANSLATION

Foreign currency translation consists of:

	2002	2001	2000
(Gain) loss on translation of foreign currency denominated long-term debt	**$ (11)**	$ 102	$ 67
Loss on translation of international subsidiaries	**63**	–	–
	$ 52	$ 102	$ 67

Note 8 INCOME TAXES

The computation of the provision for income taxes, which requires adjustment to earnings before income taxes for non-taxable and non-deductible items, is as follows:

	2002	2001	2000
Earnings before income taxes	**$ 1 828**	$ 1 329	$ 1 423
Add (deduct):			
Non-deductible royalties and other payments to provincial governments, net	**277**	413	385
Resource allowance	**(467)**	(476)	(452)
Equity in earnings of affiliates	**(9)**	(9)	(10)
Non-taxable foreign exchange	**52**	87	40
Other	**(3)**	(1)	(18)
Earnings as adjusted before income taxes	**$ 1 678**	$ 1 343	$ 1 368
Canadian Federal income tax rate	**38.0%**	38.0%	38.0%
Income tax on earnings as adjusted at Canadian Federal income tax rate	**$ 638**	$ 510	$ 520
Large Corporations Tax	**16**	15	15
Provincial and other income taxes, net of federal abatement	**27**	49	62
Future income taxes increase (decrease) due to provincial rate changes	**4**	(61)	–
Higher foreign income tax rates	**176**	–	–
Income tax credits and other	**(7)**	(30)	(33)
Provision for income taxes	**$ 854**	$ 483	$ 564
Effective income tax rate on earnings before income taxes	**46.7%**	36.3%	39.6%

Note 8 INCOME TAXES *continued*

Future income taxes consists of the following future income tax liabilities (assets) relating to temporary differences for:

	2002	2001
Property, plant and equipment	**$ 1 992**	$ 1 325
Partnership income [1]	**278**	397
Inventories	**(161)**	(78)
Deferred credits and other liabilities	**(191)**	(162)
Deferred charges and other assets	**18**	5
Loss carryforwards and other	**(115)**	(4)
	$ 1 821	$ 1 483

1 Taxable income for certain Canadian Upstream activities are generated by a partnership and the related current income taxes will be payable in the next year.

Deferred distribution taxes associated with international business operations have not been recorded. Based on current plans, repatriation of funds in excess of foreign reinvestment will not result in material additional tax expense.

Complex income tax issues that involve interpretations of continually changing regulations are encountered in computing the provision for income taxes. Management believes that adequate provision has been made for all such outstanding issues.

Note 9 EARNINGS PER SHARE

The weighted average number of common shares outstanding used in the calculation of basic earnings per share and diluted earnings per share, assuming that all dilutive outstanding stock options were exercised, was:

	2002	2001	2000
Average shares outstanding *(millions)*			
Basic	**262.8**	264.9	272.3
Diluted	**265.7**	267.4	274.6

For the year ended December 31, 2002 375 700 stock options with an exercise price of $45.68 (2001 – nil; 2000 – 274 200 stock options with an exercise price of $34.00) were excluded in the diluted earnings per share calculation as the exercise price exceeded the average share price for the respective periods.

Note 10 ITEMS NOT AFFECTING CASH FLOW

	2002	2001	2000
Depreciation, depletion and amortization	**$ 957**	$ 568	$ 584
Future income taxes	**(105)**	(45)	201
Provision for future removal and site restoration costs	**27**	17	30
(Gain) loss on translation of foreign currency denominated long-term debt	**(11)**	102	67
Foreign currency losses	**90**	–	–
Loss (gain) on disposal of assets	**2**	(49)	(73)
Other	**41**	4	31
	$ 1 001	$ 597	$ 840

Note 11 DECREASE (INCREASE) IN NON-CASH WORKING CAPITAL AND OTHER

	2002	2001	2000
Operating activities and other			
Accounts receivable	**$ (268)**	$ 465	$ (283)
Inventories	**(74)**	–	46
Prepaid expenses	**9**	5	5
Accounts payable and accrued liabilities	**467**	(433)	234
Income taxes payable	**(313)**	40	122
Current portion of long-term liabilities and other	**(47)**	(22)	(37)
	$ (226)	$ 55	$ 87
Investing activities			
Accounts receivable	**$ –**	$ 64	$ (63)
Accounts payable and accrued liabilities	**(16)**	32	19
	$ (16)	$ 96	$ (44)
Financing activities			
Accounts receivable	**$ –**	$ 2	$ (2)
Accounts payable and accrued liabilities	**–**	(2)	1
	$ –	$ –	$ (1)

Non-cash working capital is comprised of current assets and current liabilities other than cash and short-term investments and current portion of long-term debt.

Note 12 CASH AND SHORT-TERM INVESTMENTS

Short-term investments are considered to be cash equivalents and are recorded at cost, which approximates market value.

	2002	2001
Cash	**$ 139**	$ 94
Less: outstanding cheques	**167**	100
	(28)	(6)
Short-term investments	**262**	787
	$ 234	$ 781

Cash payments for interest and income taxes were as follows:

	2002	2001	2000
Interest	**$ 178**	$ 158	$ 154
Income taxes	**$ 1 172**	$ 483	$ 186

Note 13 INVENTORIES

	2002	2001
Crude oil, refined products and merchandise	$ 429	$ 377
Materials and supplies	156	78
	$ 585	$ 455

Note 14 PROPERTY, PLANT AND EQUIPMENT

	2002			2001			2002	2001
	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Cost	Accumulated Depreciation, Depletion and Amortization	Net	Capital Expenditures	
Upstream								
Canada								
North American Gas	$ 3 905	$ 1 914	$ 1 991	$ 3 618	$ 1 689	$ 1 929	$ 324	$ 406
East Coast Oil	2 637	562	2 075	2 362	326	2 036	272	257
Oil Sands	1 905	523	1 382	1 325	489	836	439	275
International	2 373	296	2 077	203	51	152	166	101
	10 820	3 295	7 525	7 508	2 555	4 953	1 201	1 039
Downstream								
Refining	2 867	1 423	1 444	2 766	1 338	1 428	222	226
Marketing and other	2 208	1 133	1 075	2 115	1 079	1 036	122	157
	5 075	2 556	2 519	4 881	2 417	2 464	344	383
Other property, plant and equipment	443	403	40	432	389	43	15	14
	$ 16 338	$ 6 254	$ 10 084	$ 12 821	$ 5 361	$ 7 460	$ 1 560	$ 1 436

Interest capitalized during 2002 amounted to $4 million (2001 – $16 million; 2000 – $12 million).

Exploration expenses of $301 million (2001 – $245 million) charged to earnings are reclassified from operating activities and included with capital expenditures under investing activities in the Consolidated Statement of Cash Flows.

Costs of $638 million (2001 – $nil) relating to the Upstream International operations and $250 million (2001 – $1 119 million) relating to non-producing East Coast Oil projects are not currently being depleted.

Capital leases at a net cost of $74 million (2001 – $78 million) and $31 million (2001 – $nil) are included in the assets of East Coast Oil and Oil Sands, respectively (Note 16).

Note 15 DEFERRED CHARGES AND OTHER ASSETS

	2002	2001
Investments	$ 77	$ 59
Deferred pension funding	34	49
Deferred financing costs	36	17
Other	65	40
	$ 212	$ 165

Note 16 LONG-TERM DEBT

	Maturity	2002	2001
Debentures and notes			
7.00% unsecured debentures			
(US $250 million)	2028	$ 395	$ 398
7.875% unsecured debentures			
(US $275 million)	2026	434	438
9.25% unsecured debentures			
(US $300 million)	2021	474	478
Capital leases *(Note 14)*[1]	2007-2017	115	87
Acquisition credit facilities[2]	2003-2005	1 639	–
		3 057	1 401
Current portion		(356)	(5)
		$ 2 701	$ 1 396

Interest on long-term debt was $182 million in 2002 (2001 – $134 million; 2000 – $138 million).

1 During 2002 the Company entered into a transportation agreement to transport bitumen from the MacKay River production facilities to the Athabasca Pipeline Terminal. The agreement is for an initial term of 15 years ending in 2017 and is extendable at the Company's option for an additional 10 years.

The Company is party to an agreement for the time charter and operation of a vessel for the transportation of East Coast Canada crude oil production. The agreement is for an initial term of 10 years ending in 2007 and extendible at the Company's option for up to an additional 15 years.

The transportation and time charter agreements are accounted for as capital leases and have implicit rates of interest of 14.65% and 11.90%, respectively. The aggregate remaining repayments under the transportation and time charter agreements are $115 million, including $6 million to $9 million in each of the next five years.

2 The Company established two unsecured credit facilities with certain banks for the acquisition of the oil and gas operations of Veba Oil & Gas GmbH (Note 3). The credit facilities, which totalled $3 320 million, can be in the form of prime loans, bankers' acceptances, U.S. base rate loans or LIBOR-based loans. In 2002, $2 100 million was drawn in the form of Canadian dollar bankers' acceptances and the Company repaid $461 million and cancelled an additional $189 million of the facilities. This reduced the amount of the facilities to $2 670 million at December 31, 2002, of which $1 639 million is outstanding. Proceeds from any future debt financing, excluding the first $100 million raised, must be used to repay the amounts outstanding under these facilities.

As at December 31, 2002, the scheduled repayments are as follows: 2003 – $350 million, 2004 – $591 million and 2005 – $698 million.

Note 17 DEFERRED CREDITS AND OTHER LIABILITIES

	2002	2001
Future removal and site restoration costs	$ 344	$ 216
Post-retirement benefits	143	133
Long-term liabilities	134	132
	$ 621	$ 481

Note 18 SHAREHOLDERS' EQUITY

	2002	2001
Common shares	$ 1 258	$ 1 228
Contributed surplus	2 138	2 138
Retained earnings	2 380	1 511
	$ 5 776	$ 4 877

The authorized share capital is comprised of an unlimited number of:

(a) Preferred shares issuable in series designated as Senior Preferred Shares
(b) Preferred shares issuable in series designated as Junior Preferred Shares
(c) Common shares

Changes in common shares were as follows:

	2002			2001		
	Shares	**Amount**	**Contributed Surplus**	Shares	Amount	Contributed Surplus
Balance at beginning of year	**262 191 041**	**$ 1 228**	**$ 2 138**	269 807 215	$ 1 238	$ 2 456
Issued for cash under employee stock option and share purchase plans	**1 403 936**	**30**	**–**	1 813 581	34	–
Purchased for cancellation	**–**	**–**	**–**	(9 429 755)	(44)	(318)
Balance at end of year	**263 594 977**	**$ 1 258**	**$ 2 138**	262 191 041	$ 1 228	$ 2 138

The Company repurchased common shares under a Normal Course Issuer Bid that commenced on November 1, 2000 and ended on October 31, 2001. During 2001 9 429 755 shares were purchased for a total cost of $362 million. The excess of purchase cost over the carrying amount of the shares purchased was recorded as a reduction of contributed surplus.

Stock Option Plan

The Company maintains a stock option plan and may grant options to directors, officers and certain employees for up to 22 million common shares. The stock options have a maximum term of 10 years, vest over periods of up to four years and are exercisable at the market prices for the shares on the dates that the options were granted.

Changes in the number of outstanding stock options were as follows:

	2002		2001	
	Shares	**Weighted-Average Exercise Price** ***(dollars)***	Shares	Weighted-Average Exercise Price *(dollars)*
Balance at beginning of year	**7 216 770**	**$ 26**	6 765 601	$ 20
Granted	**2 482 700**	**36**	2 372 500	37
Exercised	**(1 403 936)**	**22**	(1 813 581)	18
Cancelled	**(69 550)**	**30**	(107 750)	27
Balance at end of year	**8 225 984**	**$ 30**	7 216 770	$ 26

The following stock options were outstanding as at December 31, 2002:

Options Outstanding				Options Exercisable	
Number	Range of Exercise Prices *(dollars)*	Weighted-Average Life *(years)*	Weighted-Average Exercise Price *(dollars)*	Number	Weighted-Average Exercise Price *(dollars)*
53 520	$ 8 to 13	1.6	$ 10	53 520	$ 10
1 068 853	14 to 18	5.5	16	860 236	16
1 607 115	19 to 25	6.4	21	1 018 058	21
2 903 222	26 to 35	8.3	32	711 322	27
2 593 274	36 to 46	8.3	38	554 394	37
8 225 984	$ 8 to 46	7.8	$ 30	3 197 530	$ 24

Note 18 SHAREHOLDERS' EQUITY *continued*

Pro Forma Net Earnings

The following table presents the pro forma net earnings and the pro forma earnings per share computed assuming the fair value based accounting method had been used to account for the compensation cost of options that is amortized over the vesting period:

	2002 Net Earnings	Earnings per Share Basic *(dollars)*	Earnings per Share Diluted *(dollars)*
Net earnings as reported	$ 974	$ 3.71	$ 3.67
Pro forma adjustment	6	0.03	0.03
Pro forma net earnings	$ 968	$ 3.68	$ 3.64

The estimated weighted average fair value of the options of $12.74 per share has been determined using the Black-Scholes option-pricing model with the following assumptions:

Risk-free interest rate	4.9%
Expected hold period to exercise	6 years
Volatility in the market price of the common shares	33%
Estimated annual dividend	1.4%

Note 19 EMPLOYEE FUTURE BENEFITS

The Company maintains pension plans with defined benefit and defined contribution provisions, and provides certain health care and life insurance benefits to its qualifying retirees. The actuarially determined cost of these benefits is accrued over the estimated service life of employees. The defined benefit provisions are generally based upon years of service and average salary during the final years of employment. Certain defined benefit options require employee contributions and the balance of the funding for the registered plans is provided by the Company, based upon the advice of an independent actuary. The defined contribution option provides for an annual contribution of 5% to 8% of each participating employee's pensionable earnings. Substantially all of the pension assets are invested in equity, fixed income and other marketable securities.

	Pension Plans			Other Post-Retirement Plans		
Benefit Plan Expense	**2002**	2001	2000	**2002**	2001	2000
(a) Defined benefit plans						
Employer current service cost	**$ 25**	$ 22	$ 20	**$ 3**	$ 2	$ 3
Interest cost	**74**	70	69	**11**	11	10
Expected return on plan assets	**(83)**	(88)	(83)	**–**	–	–
Amortization of transitional (asset) obligation	**(5)**	(5)	(5)	**2**	2	1
Amortization of net actuarial losses	**7**	–	–	**–**	–	–
	18	(1)	1	**16**	15	14
(b) Defined contribution plans	**10**	7	6			
Total expense	**$ 28**	$ 6	$ 7	**$ 16**	$ 15	$ 14
Benefit Plan Funding	**$ 22**	$ 9	$ 6	**$ 7**	$ 7	$ 6

Financial Status of Defined Benefit Plans	Pension Plans **2002**	Pension Plans 2001	Other Post-Retirement Plans **2002**	Other Post-Retirement Plans 2001
Fair value of plan assets	**$ 927**	$ 1 039	**$ –**	$ –
Accrued benefit obligation	**1 206**	1 119	**186**	172
Funded status – plan deficit	**(279)**	(80)	**(186)**	(172)
Unamortized transitional (asset) obligation	**(39)**	(44)	**21**	23
Unamortized net actuarial losses	**352**	173	**22**	16
Accrued benefit asset (liability)	**$ 34**	$ 49	**$ (143)**	$ (133)
Reconciliation of Plan Assets				
Fair value of plan assets at beginning of year	**$ 1 039**	$ 1 113	**$ –**	$ –
Acquisition	**26**	–	**–**	–
Contributions	**22**	9	**–**	–
Benefits paid	**(61)**	(60)	**–**	–
Actual loss on plan assets	**(91)**	(17)	**–**	–
Other	**(8)**	(6)	**–**	–
Fair value of plan assets at end of year	**$ 927**	$ 1 039	**$ –**	$ –
Reconciliation of Accrued Benefit Obligation				
Accrued benefit obligation at beginning of year	**$ 1 119**	$ 1 047	**$ 172**	$ 160
Acquisition	**33**	–	**–**	–
Current service cost	**25**	22	**3**	2
Interest cost	**74**	70	**11**	11
Benefits paid	**(61)**	(60)	**(7)**	(7)
Actuarial losses	**12**	40	**7**	6
Other	**4**	–	**–**	–
Accrued benefit obligation at end of year	**$ 1 206**	$ 1 119	**$ 186**	$ 172

Funded Status

The funded status includes the following amounts in respect of plans that are not fully funded:

	Pension Plans **2002**	Pension Plans 2001	Other Post-Retirement Plans **2002**	Other Post-Retirement Plans 2001
Accrued benefit obligation	**$ (1 206)**	$ (161)	**$ (186)**	$ (172)
Fair value of plan assets	**927**	67	**–**	–
Plan deficit	**$ (279)**	$ (94)	**$ (186)**	$ (172)

Defined Benefit Plan Assumptions	**2002**	2001	2000
Year-end obligation discount rate	**6.5%**	6.5%	6.8%
Long-term rate of return on plan assets	**8.0%** [1]	8.0%	8.0%
Rate of compensation increase, excluding merit increases	**3.0%**	3.0%	2.5%
Annual increase in the per capita cost of other post-retirement benefits	**6.3%** [2]	6.2%	6.2%

1 7.5% in 2003 and thereafter.
2 4.2% in 2008 and thereafter.

Note 20 FINANCIAL INSTRUMENTS

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the course of its normal business operations. The Company monitors its exposure to market fluctuations and may use derivative instruments to manage these risks, as it considers appropriate. These derivative instruments are entered into solely for hedging purposes.

Crude Oil and Products

The Downstream business segment has entered into forward contracts and options to reduce exposure to margin fluctuations, including margins on fixed price product sales, and short-term price fluctuations on the purchase of foreign and domestic crude oil and refined products.

Natural Gas

The Company has entered into forward contracts to purchase natural gas to manage its exposure on fixed price sales of natural gas and to manage its fuel costs on fixed price product sales.

Currency

The Downstream business segment has entered into forward contracts to reduce its exposure to exchange rate movements between the Canadian dollar and the euro related to fixed price product sales.

Interest Rates

In anticipation of issuing U.S. dollar debentures in 2003, the Company has entered into interest rate derivatives to hedge a portion of its exposure to adverse interest rate fluctuations. In addition, the Company has entered into short duration Forward Rate Agreements to manage its interest rate exposure on floating rate debt.

The Company's outstanding contracts for derivative instruments and the related fair values at December 31, 2002 were as follows:

	Quantity	Average Price/Rate	Fair Value	Maturity
Crude Oil and Products *(millions of barrels)*				
Crude oil purchase	4.0	40.59[1]	$ 13	2003/2004
Products purchase	1.4	41.52[1]	1	2003
Natural Gas *(billions of cubic feet)*				
Natural gas purchase	0.6	5.99[1]	1	2003
Currency *(millions of euro)*				
Forwards purchase	3	1.5540[2]	–	2003
Interest Rates *(millions of Canadian dollars)*	624[3]	4.1516[4]	(20)	2003
			$ (5)	

1 Canadian dollars per barrel or per thousand cubic feet, as applicable.
2 Weighted-average euro forward contract rate.
3 Canadian dollar equivalent comprised of US $300 million and Cdn $150 million.
4 Weighted-average interest rate percentage.

Note 20 FINANCIAL INSTRUMENTS *continued*

Derivative instruments involve a degree of credit risk. The Company controls this risk through the establishment of credit policies and limits that are applied in the selection of counterparties. Market risk relating to changes in value or settlement cost of the Company's derivative instruments is essentially offset by gains or losses on the hedged positions.

The fair value, the related method of determination and the carrying value of the Company's financial instruments were as follows:

Current Assets/Current Liabilities

The fair value of financial instruments included in current assets and current liabilities, excluding the current portion of long-term debt, approximates the carrying amount of these instruments due to their short maturity.

Long-Term Debt

The fair value of long-term debt is based on publicly quoted market values.

Derivative Instruments

The fair value of derivative instruments, which is based on quotes provided by brokers, represents an approximation of amounts that would be received or paid to counterparties to settle these instruments prior to maturity. The Company plans to hold all derivative instruments outstanding at December 31, 2002 to maturity.

	2002		2001	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial instruments included in current assets and current liabilities	**$ (71)**	**$ (71)**	$ 381	$ 381
Long-term debt	**$ (3 057)**	**$ (3 358)**	$ (1 401)	$ (1 538)
Derivative instruments	**$ –**	**$ (5)**	$ –	$ (11)

Note 21 RELATED PARTY TRANSACTIONS

Transactions with the Government of Canada (which holds 19% of the Company's issued shares at December 31, 2002), its agencies and other related parties, are in the normal course of business and are therefore on the same terms as those accorded to non-related parties.

Note 22 COMMITMENTS AND CONTINGENT LIABILITIES

(a) The Company has leased property and equipment under various long-term operating leases for periods up to 2013. The minimum annual rentals for non-cancellable operating leases are estimated at $101 million in 2003, $84 million in 2004, $69 million in 2005, $63 million in 2006, $57 million in 2007 and $50 million per year thereafter until 2013.

(b) The Company is involved in litigation and claims associated with normal operations. Management is of the opinion that any resulting settlements would not materially affect the financial position of the Company.

Note 23 GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN THE UNITED STATES

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP, which differ in some respects from those applicable in the United States. The following are the significant differences in accounting principles as they pertain to the accompanying consolidated financial statements:

(a) Income Taxes Effective January 1, 2000 the Company adopted the recommendations of the Canadian Institute of Chartered Accountants on accounting for future income taxes and changed from the deferral method to the liability method. This liability method differs from United States GAAP due to the application of transitional provisions, the use of substantive versus enacted tax rates and the accounting for certain Canadian income tax credits and allowances.

(b) Interest Capitalization United States GAAP requires that interest be capitalized as part of the cost of certain assets while they are being prepared for their intended use. The Company capitalizes interest attributable to the construction of major new facilities and does not capitalize interest on all assets that would require interest capitalization under United States GAAP.

(c) Contributed Surplus In prior years the Company transferred amounts from contributed surplus to the accumulated deficit. Under United States GAAP these transfers would not have occurred.

(d) Derivative Instruments and Hedging Under United States GAAP the accounting for derivative instruments and hedging activities is contained in the Statement of Financial Accounting Standard No. 133 ("SFAS 133"). SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For cash flow hedges, changes in the fair value of the derivative instrument are recognized in net earnings in the same period as the hedged item and any changes in the fair value prior to that period are recognized in other comprehensive income. For fair value hedges, both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value and any changes in the fair value are recognized currently in net earnings.

(e) Minimum Pension Liability United States GAAP requires a minimum pension liability be recorded for underfunded pension plans. The change in the minimum liability, representing the excess of unfunded accumulated benefit obligations over previously recorded pension cost liabilities, is recognized in other comprehensive income.

(f) Comprehensive Income United States GAAP utilizes the concept of comprehensive income, which includes net earnings and other comprehensive income. There is no similar concept under Canadian GAAP. Other comprehensive income represents the change in equity during the period from transactions and other events from non-owner sources and includes such items as changes in the fair value of cash flow hedges, minimum pension liability adjustments and certain foreign currency translation adjustments.

The application of United States GAAP would have the following effects on earnings as reported:

	2002	2001	2000
Net earnings as reported in the consolidated statement of earnings	**$ 974**	$ 846	$ 859
Adjustments, net of applicable income taxes			
Capitalization of interest and related amortization	**15**	31	14
Accounting for income taxes	**(92)**	(29)	(35)
Other	**(2)**	(1)	1
Net earnings, as adjusted	**$ 895**	$ 847	$ 839
Earnings per share, as adjusted – basic	**$ 3.41**	$ 3.20	$ 3.08
Earnings per share, as adjusted – diluted	**$ 3.37**	$ 3.17	$ 3.06
Comprehensive Income			
Net earnings, as adjusted	**$ 895**	$ 847	$ 839
Unrealized gain (loss) on financial derivatives	**4**	(7)	–
Minimum pension liability	**(111)**	–	–
	$ 788	$ 840	$ 839

The application of United States GAAP would have the following effects on the consolidated balance sheets as reported:

	December 31, 2002		December 31, 2001	
	As Reported	United States GAAP	As Reported	United States GAAP
Current assets	$ 2 434	$ 2 434	$ 2 009	$ 2 009
Property, plant and equipment, net	10 084	10 662	7 460	8 037
Goodwill	709	688	–	–
Deferred charges and other assets	212	209	165	158
Current liabilities	2 520	2 525	1 397	1 408
Long-term debt	2 701	2 701	1 396	1 396
Deferred credits and other liabilities	621	808	481	481
Future income taxes	1 821	2 073	1 483	1 746
Common shares	1 258	1 258	1 228	1 228
Contributed surplus	2 138	3 260	2 138	3 260
Retained earnings	2 380	1 482	1 511	692
Accumulated other comprehensive income (loss)	$ –	$ (114)	$ –	$ (7)

Recent Accounting Pronouncements

United States GAAP requires the disclosure of accounting pronouncements that have been issued but are not yet effective for the Company's reporting. The following applicable accounting pronouncements have been recently issued:

Guarantees

In November 2002, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" ("FIN 45"). FIN 45 elaborates on the disclosures to be made by a guarantor about its obligations under certain guarantees issued and clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. Several situations are identified where the recognition of a liability at inception for a guarantor's obligation is not required. The initial recognition and measurement provisions of FIN 45 apply on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure provisions are effective for periods ending after December 15, 2002. The impact of adopting the interpretation on the Company's United States GAAP consolidated financial statements has not been determined.

Asset Retirement Obligations

In June 2001, the FASB issued Statement No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 requires companies to record the fair value of legal obligations associated with the retirement of tangible long-lived assets in the period in which they are incurred. The liability is capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. SFAS 143 is effective for all fiscal years beginning after June 15, 2002. The effect of adopting SFAS 143 on the Company's United States GAAP consolidated financial statements has not been determined.

SUPPLEMENTAL INFORMATION

Proved Developed and Undeveloped Reserves Before Royalties [1,2]

(Crude oil and equivalents in millions of barrels; natural gas in billions of cubic feet)

	NORTH AMERICA						
	WESTERN CANADA		EAST COAST [4]	OIL SANDS		SUBTOTAL	
	Crude Oil and Liquids	Natural Gas	Crude Oil	Synthetic Crude Oil [5]	Bitumen [6]	Crude Oil and Liquids	Natural Gas
Beginning of year 2001	**54**	**2 331**	**38**	**320**	**–**	**412**	**2 331**
Revisions of previous estimates [14]	1	8	–	–	–	1	8
Sale of reserves in place	(2)	(120)	–	–	–	(2)	(120)
Purchase of reserves in place	–	9	–	–	–	–	9
Discoveries, extensions and improved recovery	7	261	15	–	33	55	261
Production	(6)	(261)	(11)	(10)	–	(27)	(261)
End of year 2001	**54**	**2 228**	**42**	**310**	**33**	**439**	**2 228**
Revisions of previous estimates [14]	3	(49)	52	24	–	79	(49)
Sale of reserves in place	–	(5)	–	–	–	–	(5)
Purchase of reserves in place	–	14	–	–	–	–	14
Discoveries, extensions and improved recovery	5	256	–	–	–	5	256
Production	(7)	(263)	(26)	(10)	(1)	(44)	(263)
End of year 2002	**55**	**2 181**	**68**	**324**	**32**	**479**	**2 181**

Probable Reserves Before Royalties [1,3]

(Crude oil and equivalents in millions of barrels; natural gas in billions of cubic feet)

	NORTH AMERICA						
	WESTERN CANADA		EAST COAST [7]	OIL SANDS		SUBTOTAL	
	Crude Oil and Liquids	Natural Gas	Crude Oil	Synthetic Crude Oil [5]	Bitumen [7]	Crude Oil and Liquids	Natural Gas
End of year 2001	**25**	**883**	**205**	**134**	**215**	**579**	**883**
Revisions of previous estimates [14]	(6)	(150)	24	(1)	–	17	(150)
Sale of reserves in place	–	–	–	–	–	–	–
Purchase of reserves in place	–	7	–	–	–	–	7
Discoveries, extensions and improved recovery	–	22	–	–	–	–	22
End of year 2002	**19**	**762**	**229**	**133**	**215**	**596**	**762**

1 Proved developed and undeveloped and probable reserves before royalties are Petro-Canada's working interest in reserves before the deduction of Crown or other royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. No reserve quantities have been included to reflect royalty interests Petro-Canada has in various properties.

2 Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those proved reserves which are expected to be recovered from existing wells or facilities. Proved undeveloped reserves are proved reserves which are not recoverable from existing wells or facilities, but are expected to be recovered through additional development drilling or through the upgrading of existing or additional new facilities.

3 Unproved reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves. Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to be recovered than not.

4 Proved reserves at Hibernia and Terra Nova are based on primary recovery for drilled fault blocks and undrilled fault blocks which lie between drilled fault blocks plus incremental recovery in fault blocks showing response to water or gas injection.

INTERNATIONAL								TOTAL	
NORTHWEST EUROPE [8]		NORTH AFRICA AND NEAR EAST [9,10,11]		NORTHERN LATIN AMERICA [12,13]		SUBTOTAL			
Crude Oil and Liquids	Natural Gas	Crude Oil and Liquids	Natural Gas	Crude Oil and Liquids	Natural Gas	Crude Oil and Liquids	Natural Gas	**Crude Oil and Liquids**	**Natural Gas**
–	–	2	–	–	–	2	–	414	2 331
–	–	–	–	–	–	–	–	1	8
–	–	–	–	–	–	–	–	(2)	(120)
–	–	10	–	–	–	10	–	10	9
–	–	–	–	–	–	–	–	55	261
–	–	(1)	–	–	–	(1)	–	(28)	(261)
–	–	11	–	–	–	11	–	450	2 228
3	11	45	10	–	–	48	21	127	(28)
–	–	–	–	–	–	–	–	–	(5)
59	149	269	78	–	346	328	573	328	587
10	22	–	–	–	–	10	22	15	278
(10)	(22)	(36)	(11)	–	(5)	(46)	(38)	(90)	(301)
62	160	289	77	–	341	351	578	830	2 759

INTERNATIONAL								TOTAL	
NORTHWEST EUROPE [8]		NORTH AFRICA AND NEAR EAST [9,10,11]		NORTHERN LATIN AMERICA [12,13]		SUBTOTAL			
Crude Oil and Liquids	Natural Gas	Crude Oil and Liquids	Natural Gas	Crude Oil and Liquids	Natural Gas	Crude Oil and Liquids	Natural Gas	**Crude Oil and Liquids**	**Natural Gas**
–	–	43	221	–	–	43	221	622	1 104
(4)	(17)	(66)	(221)	–	–	(70)	(238)	(53)	(388)
–	–	–	–	–	–	–	–	–	–
22	45	152	–	–	67	174	112	174	119
10	88	–	–	–	–	10	88	10	110
28	116	129	–	–	67	157	183	753	945

5 Proved and probable reserves of synthetic crude oil are based on high geological certainty and application of proven or piloted technology. For proved reserves, drill hole spacing is less than 500 metres and appropriate co-owner and regulatory approvals are in place. For probable reserves, drill hole spacing is less than 1 000 metres, appropriate co-owner approvals are in place and regulatory approvals are being sought.

6 Proved reserves at MacKay River are based on conservative estimates of recovery from existing producer-injector well pairs.

7 Probable reserves at Hibernia, Terra Nova and MacKay River are based on estimates of the ultimate recovery from the current depletion plans for the properties, less volumes produced or included in proved reserves.

8 Reserves in Northwest Europe are subject to a conventional royalty and tax regime. No royalty is payable on reserves in the U.K. sector. Royalty is payable on onshore reserves in the Netherlands.

9 Reserves in Syria and Kazakhstan are held under production sharing arrangements with the governments. The State share is split between royalty and tax for Canadian reporting purposes.

10 With the exception of the En Naga field, reserves in Libya are held under a concession and are subject to a royalty and tax regime. The En Naga field is held under a production sharing arrangement, with the government's share being split between royalty and tax for Canadian reporting purposes.

11 Reserves in Algeria are held under a production sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes.

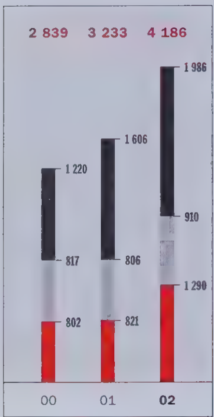
12 Crude oil reserves in Venezuela are subject to a conventional royalty and tax regime.

13 Natural gas reserves in Trinidad are held under a production sharing arrangement with the government. The State share is split between royalty and tax for Canadian reporting purposes.

14 Revisions include changes in previous estimates, either upward or downward, resulting from new information (except an increase in acreage) normally obtained from drilling or production history or resulting from a change in economic factors. Revisions also include movements of reserves between classes as a result of development activity, e.g., from probable or proved undeveloped reserves to proved developed reserves as a result of the drilling and completion of a well.

Reserves Inventory

Our large reserves inventory provides a strong base for future growth.



- Proved reserves *(millions of barrels of oil equivalent)*
- Probable reserves *(millions of barrels of oil equivalent)*
- Possible reserves *(millions of barrels of oil equivalent)*

– (Caution should be exercised in aggregating proved, probable and possible reserves. There is a 90 per cent probability that actual reserves will equal or exceed proved reserves, a 50 per cent probability that actual reserves will equal or exceed the sum of proved and probable reserves and a 10 per cent probability that actual reserves will equal or exceed the sum of proved, probable and possible reserves).

Principal Reserves and Production Locations

Crude Oil Fields	Proved Reserves Before Royalties at December 31, 2002[1] *(millions of barrels)*	Per Cent of Total Proved Oil Reserves	Average 2002 Daily Production Before Royalties[1,2] *(thousands of barrels)*	Per cent of Total 2002 Daily Oil Production
Syncrude, Alberta	324	41	27	12
Ghani/Zenad Farud, Libya	54	7	9	4
Amal, Libya	53	7	10	4
Hibernia, Newfoundland	38	5	36	16
MacKay River, Alberta[2]	32	4	1	1
Terra Nova, Newfoundland[2]	30	4	36	16
Ghani Gir/Facha, Libya	22	3	3	1
Guillemot West & N.W., United Kingdom	17	2	10	4
Omar, Syria	17	2	10	4
Scott, United Kingdom	16	2	5	2
Other	187	23	83	36
Total	**790**	**100**	**230**	**100**

Natural Gas Fields	Proved Reserves Before Royalties at December 31, 2002[1] *(billions of cubic feet)*	Per cent of Total Proved Gas Reserves	Average 2002 Daily Production Before Royalties[1,2] *(millions of cubic feet)*	Per cent of Total 2002 Daily Gas Production
Wildcat Hills area, Alberta	559	20	157	19
NCMA-1, Trinidad[2]	341	12	13	1
Hanlan area, Alberta	273	10	100	12
Jedney/Beg/Bubbles, British Columbia	228	8	40	5
Ricinus/Bearberry area, Alberta	175	6	98	12
Medicine Hat, Alberta	156	6	33	4
Laprise area, British Columbia	121	4	39	5
Gilby/Wilson Creek, Alberta	98	4	31	4
Alderson, Alberta	81	3	23	3
Ferrier, Alberta	77	3	22	3
Other	650	24	269	32
Total	**2 759**	**100**	**825**	**100**

1 Does not include natural gas liquids.
2 The Terra Nova field commenced production in January; NCMA-1 commenced production in August; the MacKay River development commenced production in November.

Oil and Gas Landholdings

(Gross[1] / Net[2]) *(millions of acres)*	Developed[3] Gross	Developed[3] Net	Undeveloped[4] Gross	Undeveloped[4] Net	Total Gross	Total Net
Mainland Canada[5]	2.09	1.02	4.00	2.76	6.09	3.78
Oil Sands	0.26	0.03	0.68	0.30	0.94	0.33
East Coast Offshore	0.09	0.02	5.05	1.71	5.14	1.73
Other Frontier Canada	–	–	7.49	6.19	7.49	6.19
Alaska	–	–	0.41	0.41	0.41	0.41
Total North America	2.44	1.07	17.63	11.37	20.07	12.44
Northwest Europe	0.11	0.07	2.52	0.61	2.63	0.68
North Africa & Near East	0.91	0.38	9.15	6.09	10.06	6.47
Northern Latin America	0.03	0.01	0.21	0.07	0.24	0.08
Total International	1.05	0.46	11.88	6.77	12.93	7.23
Total	**3.49**	**1.53**	**29.51**	**18.14**	**33.00**	**19.67**

1 Includes interests of others.
2 Excludes interests of others.
3 Areas capable of production.
4 Areas with rights to explore.
5 Includes Mackenzie Delta.

QUARTERLY FINANCIAL AND STOCK TRADING INFORMATION

(unaudited, stated in millions of dollars unless otherwise indicated)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2002	First Quarter	Second Quarter	Third Quarter	Fourth Quarter 2001
Revenue								
Operating	**$ 1 701**	**$ 2 441**	**$ 2 773**	**$ 3 002**	$ 2 476	$ 2 277	$ 2 072	$ 1 757
Investment and other income	**7**	**(4)**	**(6)**	**3**	86	30	17	21
	1 708	**2 437**	**2 767**	**3 005**	2 562	2 307	2 089	1 778
Expenses								
Crude oil and product purchases	**885**	**1 107**	**1 298**	**1 266**	1 249	1 239	1 233	966
Operating, marketing and general	**397**	**494**	**528**	**617**	408	391	408	463
Exploration	**106**	**44**	**79**	**72**	111	38	37	59
Depreciation, depletion and amortization	**162**	**240**	**276**	**279**	139	148	134	147
Foreign currency translation	**1**	**(47)**	**82**	**16**	92	(71)	71	10
Interest	**30**	**45**	**56**	**56**	38	34	36	27
	1 581	**1 883**	**2 319**	**2 306**	2 037	1 779	1 919	1 672
Earnings Before Income Taxes	**127**	**554**	**448**	**699**	525	528	170	106
Provision for Income Taxes	**39**	**233**	**239**	**343**	243	129	71	40
Net Earnings	**$ 88**	**$ 321**	**$ 209**	**$ 356**	$ 282	$ 399	$ 99	$ 66
Cash Flow	**$ 287**	**$ 540**	**$ 642**	**$ 807**	$ 629	$ 454	$ 298	$ 307
Earnings								
Upstream								
Canada	**$ 73**	**$ 174**	**$ 194**	**$ 248**	$ 280	$ 230	$ 127	$ 53
International	**(6)**	**58**	**78**	**95**	(24)	–	(2)	(1)
Downstream	**45**	**73**	**58**	**78**	91	111	50	48
Shared Services	**(23)**	**(29)**	**(41)**	**(51)**	(11)	(7)	(8)	(25)
Earnings from operations	**89**	**276**	**289**	**370**	336	334	167	75
Foreign currency translation	**(1)**	**45**	**(80)**	**(16)**	(85)	65	(67)	(9)
Gain (loss) on sale of assets	**–**	**–**	**–**	**2**	31	–	(1)	–
Net earnings	**$ 88**	**$ 321**	**$ 209**	**$ 356**	$ 282	$ 399	$ 99	$ 66
Share Information *(dollars per share)*								
Earnings								
– Basic	**$ 0.34**	**$ 1.22**	**$ 0.79**	**$ 1.35**	$ 1.05	$ 1.50	$ 0.38	$ 0.25
– Diluted	**0.33**	**1.21**	**0.79**	**1.34**	1.04	1.48	0.37	0.25
Cash flow	**1.09**	**2.06**	**2.44**	**3.06**	2.34	1.71	1.13	1.17
Dividends per share	**0.10**	**0.10**	**0.10**	**0.10**	0.10	0.10	0.10	0.10
Share price [1]								
– High	**42.05**	**44.48**	**48.85**	**50.15**	38.60	43.65	42.01	43.50
– Low	**33.90**	**39.33**	**36.89**	**42.90**	33.50	35.05	35.33	35.09
– Close *(end of period)*	**$ 41.06**	**$ 42.75**	**$ 46.56**	**$ 48.91**	$ 35.44	$ 36.02	$ 38.97	$ 39.31
Shares traded *(millions)* [2]	**63.9**	**37.5**	**49.8**	**45.2**	59.4	65.3	37.9	49.4

1 Share prices are for trading on the Toronto Stock Exchange.
2 Total shares traded on the Toronto and New York stock exchanges.

FIVE-YEAR FINANCIAL AND OPERATING SUMMARY

(stated in millions of dollars, unless otherwise indicated)

	2002	2001	2000	1999	1998
Consolidated					
Revenue	**$ 9 917**	$ 8 736	$ 9 545	$ 6 168	$ 5 040
Expenses	**8 089**	7 407	8 122	5 621	4 888
Provision for income taxes	**854**	483	564	229	103
Net Earnings	**$ 974**	$ 846	$ 859	$ 318	$ 49
Cash flow	**2 276**	1 688	1 870	964	830
Total assets	**13 439**	9 634	10 000	8 574	8 186
Average capital employed	**7 826**	6 259	5 883	5 645	5 560
Operating return on capital employed *(per cent)*[1]	**14.5**	15.8	16.4	5.9	3.9
Return on capital employed *(per cent)*	**13.9**	14.8	16.0	7.1	2.1
Debt	**3 057**	1 401	1 774	1 711	1 829
Debt to debt plus equity *(per cent)*	**34.6**	22.3	28.4	30.0	32.7
Debt to cash flow *(times)*	**1.3**	0.8	0.9	1.8	2.2
Expenditures on property, plant and equipment and exploration	**1 861**	1 681	1 203	1 021	1 116
Employees *(number at year end)*	**4 470**	4 178	4 024	4 417	4 620
Shareholders' Data					
Weighted average number of common shares outstanding *(millions)*	**262.8**	264.9	272.3	271.5	271.2
Shares outstanding at year end *(millions)*[2]	**263.6**	262.2	269.8	271.8	271.3
Publicly held shares at year end *(millions)*	**214.2**	212.8	220.4	222.4	221.9
Share prices *(dollars)*[3]					
– at year end	**48.91**	39.31	38.15	20.45	16.25
– range during the year	**33.90-50.15**	33.50-43.65	19.00-38.45	15.35-25.10	14.55-26.95
Shares traded *(millions)*[4]	**196.4**	212.0	224.8	184.7	244.7
Book value per share *(dollars)*	**21.91**	18.60	16.55	14.68	13.85

1 Earnings from operations are earnings before gains or losses on foreign currency translation and on disposal of assets. In 2000 and 1998, earnings from operations are before reorganization costs.

2 Includes 49.4 million shares held as an investment by the Government of Canada.

3 Year-end prices and ranges are from the Toronto Stock Exchange.

4 Total shares traded on the Toronto and New York stock exchanges.

	2002	2001	2000	1999	1998
Upstream Canada					
Earnings from operations	**$ 689**	$ 690	$ 685	$ 249	$ 38
Gain (loss) on sale of assets	**(1)**	29	113	6	30
Net earnings	**$ 688**	$ 719	$ 798	$ 255	$ 68
Cash flow	**1 417**	1 125	1 460	841	481
Expenditures on property, plant and equipment and exploration	**1 281**	1 131	884	746	746
Daily production *(net, before royalties)*					
Crude oil and liquids *(thousands of barrels)*	**119.4**	75.1	76.6	83.1	89.2
Natural gas *(millions of cubic feet)*	**722**	714	738	719	722
Average sale price					
Crude oil and liquids *(per barrel)*[1]	**37.95**	37.24	41.42	24.48	18.00
Natural gas *(per thousand cubic feet)*[1,2]	**4.01**	6.00	4.75	2.59	1.96
Proved reserves *(net, before royalties)*					
Crude oil and liquids *(millions of barrels)*	**479**	439	412	463	463
Natural gas *(trillions of cubic feet)*	**2.2**	2.2	2.3	2.5	2.5
Oil and gas landholdings *(gross/net) (millions of acres) (includes Alaska)*	**20.1/12.4**	21.1/12.7	19.4/12.0	18.6/11.5	15.9/10.0
Wells drilled *(gross/net)*					
Oil	**17/7**	27/15	34/21	44/12	67/30
Natural gas	**348/203**	354/229	233/135	164/95	187/82
Oil Sands	**0/0**	50/50	0/0	0/0	0/0
Dry	**32/21**	27/16	20/4	24/6	21/8
Total	**397/231**	458/310	287/160	232/113	275/120
Upstream International					
Earnings (loss) from operations	**$ 225**	$ (27)	$ 19	$ (6)	$ (9)
Loss on sale of assets	**–**	–	(41)	–	–
Net earnings (loss)	**$ 225**	$ (27)	$ (22)	$ (6)	$ (9)
Cash flow	**583**	27	78	44	35
Expenditures on property, plant and equipment and exploration	**221**	153	43	47	72
Daily production *(net, before royalties)*					
Crude oil and liquids *(thousands of barrels)*	**125.5**	2.3	12.6	12.2	11.9
Natural gas *(millions of cubic feet)*	**103**	–	–	–	–
Average sale price					
Crude oil and liquids *(per barrel)*[1]	**39.53**	37.62	41.96	24.92	17.17
Natural gas *(per thousand cubic feet)*[1]	**4.52**	–	–	–	–
Proved reserves *(net, before royalties)*					
Crude oil and liquids *(millions of barrels)*	**351**	11	2	13	13
Natural gas *(trillions of cubic feet)*	**0.6**	–	–	–	–
Oil and gas landholdings *(gross/net) (millions of acres)*	**12.9/7.2**	5.7/5.7	3.3/3.3	3.4/3.4	3.3/3.3
Wells drilled *(gross/net)*					
Oil	**39/17**	3/1	7/0	7/1	9/3
Natural gas	**5/1**	0/0	1/0	0/0	1/1
Dry	**9/4**	0/0	3/2	2/2	2/1
Total	**53/22**	3/1	11/2	9/3	12/5
Downstream					
Earnings from operations	**$ 254**	$ 300	$ 273	$ 115	$ 204
Gain (loss) on sale of assets	**3**	1	(1)	(9)	(35)
Net earnings	**$ 257**	$ 301	$ 272	$ 106	$ 169
Cash flow	**380**	589	434	163	420
Expenditures on property, plant and equipment	**344**	383	264	220	276
Petroleum product sales *(thousands of cubic metres per day)*	**55.7**	54.5	55.4	51.2	49.1
Retail outlets at year end	**1 537**	1 566	1 618	1 658	1 709
Refinery crude capacity at year end *(thousands of cubic metres per day)*	**49.8**	49.8	49.8	49.0	49.0
Average refinery utilization *(per cent)*	**101**	96	101	100	95

1 After the impact of hedging activities.
2 Before deduction of British Columbia gathering and processing charges.

EXECUTIVE LEADERSHIP TEAM

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Chief Executive Officer

Norm McIntyre
President

Boris Jackman
Executive Vice-President, Downstream

Harry Roberts
Senior Vice-President and
Chief Financial Officer

Kathy Sendall
Senior Vice-President, Western Canada

Brant Sangster
Senior Vice-President, Oil Sands

Gordon Carrick
Vice-President, East Coast

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Please see the Management Proxy Circular for additional information about Petro-Canada's Senior Officers, Board of Directors and governance practices. The Management Proxy Circular contains: biographical information on Senior Officers; disclosure on executive compensation and contracts; mandates and reports of Board committees; a Statement of Corporate Governance Practices; and detail on Directors' business background, tenure, committee membership, remuneration and share ownership. The Management Proxy Circular is available for viewing on our Web site at www.petro-canada.ca or by contacting Investor Relations.

INVESTOR INFORMATION

Outstanding Shares
At December 31, 2002, Petro-Canada's public float was 214.2 million shares.

Transfer Agent and Registrar
In Canada:
CIBC Mellon Trust Company

In the United States:
Mellon Investor Services, LLC

Telephone toll free: 1-800-387-0825
Fax: (416) 643-5660 or
(416) 643-5661
E-mail: inquiries@cibcmellon.com
Web site: www.cibcmellon.com

Duplicate Reports
Shareholders with more than one unregistered account may receive duplicate materials. To eliminate duplicate mailings, contact the transfer agent and registrar.

Annual Meeting
The annual meeting of shareholders will be held at 11:00 a.m. local time Tuesday, April 29, 2003, The Palliser Hotel, Crystal Ballroom, 133 – 9th Avenue S.W., Calgary, Alberta

Stock Exchange Listings and Symbols
Toronto: PCA
New York: PCZ

Dividends
Petro-Canada's Board of Directors has adopted a policy of paying quarterly dividends of $0.10 ($0.40 per annum) per common share. The Board regularly reviews the dividend policy in light of the company's financial position, its financing requirements for growth, and other factors.

On Our Web Site...
Petro-Canada's Web site, www.petro-canada.ca, contains a variety of corporate and investor information, including:

- Statistical Supplement
- Annual Information Form
- Quarterly Reports
- Management Proxy Circular
- Presentations and Speeches
- Dividend History
- Petro-Canada's Code of Business Conduct
- Petro-Canada's Principles for Investment and Operations
- Report to the Community

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Fax: (403) 296-3030
Web site: www.petro-canada.ca

We'd Like Your Feedback
We invite your comments on our low-cost annual report format. Please e-mail your comments to: sbraunga@petro-canada.ca

GLOSSARY OF FINANCIAL TERMS AND RATIOS

Terms

BARREL OF OIL EQUIVALENT:
Natural gas production (excluding injectants) is converted using 6 000 cubic feet of gas for one barrel of oil.

CAPITAL EMPLOYED:
Total of shareholders' equity and debt.

CASH FLOW:
Cash flow from operations before changes in non-cash working capital items.

DEBT:
Long-term debt including current portion.

EARNINGS FROM OPERATIONS:
Earnings before gains or losses on foreign currency translation and on asset sales.

Ratios

RETURN ON CAPITAL EMPLOYED:
Net earnings plus after-tax interest expense divided by average capital employed. Measures net earnings relative to the capital employed in the Company.

OPERATING RETURN ON CAPITAL EMPLOYED:
Earnings from operations plus after-tax interest expense divided by average capital employed.

RETURN ON EQUITY:
Net earnings divided by average shareholders' equity. Measures the return earned by shareholders on their investment in the Company.

DEBT TO CASH FLOW:
Debt divided by cash flow. Indicates the Company's ability to discharge its outstanding debt.

DEBT TO DEBT PLUS EQUITY:
Debt divided by debt plus equity. Indicates the relative amount of debt in the Company's capital structure. Measures financial strength.

INTEREST COVERAGE:
Measures the Company's ability to cover interest charges on debt.

Earnings basis: Earnings before interest expense and provision for income taxes divided by interest expense plus capitalized interest.

EBITDAX basis: Earnings before interest expense, income taxes, depreciation, depletion and amortization and exploration expenses divided by interest expense plus capitalized interest.

Cash flow basis: Cash flow before interest expense and current income taxes divided by interest expense plus capitalized interest.

Conversion Factors

To conform with common usage, imperial units of measurement are used in this report to describe exploration and production, while metric units are used for refining and marketing. Dollars are Canadian unless otherwise stated.

1 cubic metre (liquids) = 6.29 barrels
1 cubic metre (natural gas) = 35.49 cubic feet
1 litre = 0.22 imperial gallon
1 hectare = 2.47 acres
1 cubic metre = 1 000 litres

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A VERY CAPABLE COMPANY

Petro-Canada is focused and disciplined, with the financial and human capability to execute our strategy.

A HIGHLY PRINCIPLED COMPANY

We consider high standards of honesty, integrity and ethical behaviour as key to our success, and apply these standards wherever we operate.

BUILDING A TRACK RECORD OF SUCCESS

Our plans for continued profitability improvement and growth position us to extend our record of building shareholder value.

POSITIONED FOR A WORLD-CLASS FUTURE

We are disciplined in where and how we invest, building a portfolio of world-class opportunities.

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